UIC PERMIT APPLICATION
FOR
NEW INJECTION WELL
(WAL/SPL-1)

FOR

BETHLEHEM STEEL CORPORATION, INC.
BURNS HARBOR DIVISION
BURNS HARBOR, INDIANA

MARCH 1999

TWO

TEXAS WORLD OPERATIONS INC
520 POST OAK BLVD SUITE 450
HOUSTON TEXAS 77027-9405
(713) 850-0003

Bethlehem Steel Corporation

BURNS HARBOR DIVISION
BOX 248
CHESTERTON, IN 46304

March 24, 1999
Ref: PF/UIC/GEN

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Ms. Valerie Jones, Branch Chief
Underground Injection Control (UIC) Section, WDU-17J
United States Environmental Protection Agency, Region V
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

Subject: Underground Injection Control Permit Application
Bethlehem Steel Corporation, Burns Harbor Division

Dear Ms. Jones:

Enclosed, for your review and approval, are two (2) copies of an application to drill a new Class 1 disposal well at the Burns Harbor Division. The proposed well will be designed to inject either Waste Ammonia Liquor or Spent Pickle Liquor, which are currently injected into wells that have operable UIC permits. The purpose of the proposed well is to be a back-up to the currently permitted wells. The submittal of this application has been previously discussed with Mr. N. Wiser, of your staff, and is expected.

If there are any questions concerning this matter, please contact me or D. P. Bley at (219) 787-2712.

Very truly yours,

T. W. Easterly, P.E., DEE
Superintendent
Environmental Services Department

Enclosures

Cc: R. W. Anderson
H. E. Harrington
W. J. Riley/R. K. Chaturvedi

UIC PERMIT APPLICATION
FOR
NEW INJECTION WELL
(WAL/SPL-1)

FOR

BETHLEHEM STEEL CORPORATION
BURNS HARBOR DIVISION
BURNS HARBOR, INDIANA

PREPARED BY:
TEXAS WORLD OPERATIONS, INC.
520 POST OAK BOULEVARD, SUITE 450
HOUSTON, TEXAS
(713) 850-0003

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FIGURES

APPENDICES

SECTION 1 - INTRODUCTION

Bethlehem Steel Corporation, Inc. (BSC) is applying for an Underground Injection Control (UIC) permit from Region 5 of the United States Environmental Protection Agency (USEPA) for a new Class I, non-commercial, hazardous waste injection well to be installed at its Burns Harbor Division, in northwestern Indiana. The new proposed well is designed for the dual purpose of injecting either waste ammonia liquor (WAL) or spent pickle liquor (SPL) into the Cambrian age lower Mt. Simon Sandstone Formation, below the B-Cap Shale. The proposed designation for the new well is well "WAL/SPL-1".

BSC presently operates three Class 1 injection wells at its Burns Harbor Division. One well already injects spent pickle liquor (SPL) derived from cleaning mill scale and oxides from steel during the finishing process. Two wells inject waste ammonia liquor (WAL) which is derived from the coke making process. The wells operate under authority of existing UIC permits issued by the USEPA, Region 5. Applicable permit numbers for the existing wells are as follows:

Well	Permit Number	Stated Expiration Date
SPL-1	IN-127-1W-0001	10/30/91
WAL-1	IN-127-1W-0003	10/30/90
WAL-2	IN-127-1W-0004	10/30/90

Permit renewal applications were filed in April 1990 and April 1991. On October 15, 1997 Bethlehem Steel filed supplements to the permit renewal applications for the existing wells in response to a notice of deficiency received from the EPA regarding the 1990 / 1991 permit applications. In the interim period, the existing permits have continued in effect.

The three existing wells have been adequate to meet the plant's disposal needs since installation. Through the years, remedial work has been required on all three of the wells. The historical work is currently limiting the repair options that may be become necessary in the future. This condition could lead to inadequate disposal capability. Therefore, BSC is seeking approval to construct a new well that will be capable of injecting either spent pickle liquor or waste ammonia liquor as the need arises. The design of the proposed well includes materials of construction that are suitable for the injection of either waste stream. A buffer solution will be injected between the waste streams to protect the injection interval.

Installation of the new well will greatly enhance the reliability of the current BSC injection facilities by insuring a well is always ready in the event an existing well must be removed from service for maintenance, repairs or testing. The new well is not being installed to increase the current waste volume permitted in the existing UIC permits or increase the volume used in the mathematical simulation modeling contained within the approved petition for exemption from Land-Ban regulations.

The new well is to be installed on the western side of the BSC Burns Harbor property, at a location approximately 450 feet north-northeast of the existing WAL-1 well, and approximately 7400 feet west-southwest of the existing SPL-1 well. The subsurface geological and hydrological conditions at the proposed location for WAL/SPL-1are expected to be very similar to that encountered in Bethlehem's presently operating WAL and SPL wells.

1.1 ORGANIZATION OF MATERIALS

This document presents the required UIC permit application data and necessary attachments in the order they are requested in the instructions for completing the application materials. Since BSC currently has UIC applications pending with the USEPA for existing wells at the Burns Harbor Division, the data required to document WAL/SPL-1 is incorporated by reference to the previously provided application materials where applicable. When well specific information is required, such as in the areas of well construction, installation procedures, testing, monitoring or closure and post closure, the information is included with this application.

1.2 SOURCES OF DATA

To a large degree, information presented in this document and in the referenced UIC applications that are currently pending has been extracted from Bethlehem's 1990 Petition for exemption from the hazardous waste restrictions. In 1990 Bethlehem was granted an exemption to continue injection of hazardous waste subject to the Land Disposal Restrictions (LDR's) of the Hazardous and Solid Waste Amendments of 1984. This exemption was modified in 1998 to include additional waste codes that later became subject to the LDR's. Where necessary, information in this document or the referenced applications has been updated or revised to reflect changes that have occurred since the petition was prepared.

1.3 PERMIT PARAMETERS

Bethlehem is requesting that the permit parameters for WAL/SPL-1 be similar to those in the existing UIC permits for WAL and SPL injection. Bethlehem requests that the new well be permitted to inject directly into the lower Mt. Simon Formation (Injection Interval) below the approximate depth of 2745 feet below ground level, which is below the B-Cap Shale. An Injection Zone consisting of the Eau Claire Sandstone, the Upper Mt. Simon Sandstone, the B-Cap shale and the Lower Mt. Simon Sandstone is requested. The Eau Claire Sandstone, the upper Mt. Simon Sandstone and the B-Cap shale are designated as the Containment Interval of the Injection Zone and the lower Mt. Simon is designated as the Injection Interval. A Confining Zone consisting of the Eau Claire Shale is requested.

The WAL/SPL-1 maximum surface injection pressure shall be limited based on the results obtained from the injection interval fracture gradient determination that will be performed during installation. The current allowable maximum injection pressures for WAL and SPL are 977 psig and 699 psig, respectively. It is anticipated that the proposed fracture gradient determination will yield values which allow for equivalent maximum injection pressures.

The injection rate for WAL shall be limited to a combined monthly average maximum of 240 gallons per minute, calculated for all wells injecting WAL.

SECTION 2 - WELL PERMIT APPLICATION FORMS

The United States Environmental Protection Agency, Underground Injection Control Permit Application Form and Plugging and Abandonment Plan for Bethlehem Steel's proposed new injection well: WAL/SPL-1 are found on the following pages.

Form Approved. OMB No. 2040-0042. Expires 6-30-98

EPA

United States Environmental Protection Agency
Underground Injection Control Permit Application
(Collected under the authority of the Safe Drinking Water Act. Sections 1421, 1422, 40 CFR 144)

I. EPA ID Number IND003913423

WRITER

U WiSER. T/A C

Read Attached Instructions Before Starting

RcV'c 3-29-99 For Official Use Only ASSN 4-7-99

Application approved mo	day	year	Date received mo	day	year	Permit Number	Well ID	FINDS Number
						IN-127-1W-0007		

II. Owner Name and Address			III. Operator Name and Address		
Owner Name: Bethlehem Steel Corp., Inc. WAL/SPL-1			Operator Name: Bethlehem Steel Corp., Inc. WAL/SPL-1		
Street Address: Burns Harbor Division PO Box 248		Phone Number: (219) 787-2712	Street Address: Burns Harbor Division PO Box 248		Phone Number: (219) 787-2712
City: Chesterton	State: IN	ZIP CODE: 46304	City: Chesterton	State: IN	ZIP CODE: 46304

IV. Commercial Facility	V. Ownership	VI. Legal Contact	VII. SIC Codes
[ ] Yes [X] No	[X] Private [ ] Federal [ ] Other	[X] Owner [ ] Operator	331

VIII. Well Status *(Mark "x")*

[ ] A. Operating	Date Started mo / day / year	[ ] B. Modification/Conversion	[X] C. Proposed

IX. Type of Permit Requested *(Mark "x" and specify if required)*

[X] A. Individual	[ ] B. Area	Number of Existing Wells	Number of Proposed Wells	Name(s) of field(s) or project(s)
		3	1	

X. Class and Type of Well *(see reverse)*

A. Classes(es) (enter codes(s))	B. Type(s) (enter codes(s))	C. If class is "other" or type is code 'x,' explain	D. Number of wells per type (if area permit)
1	W		

XI. Location of Well(s) or Approximate Center of Field or Project / XII. Indian Lands (Mark 'x')

Latitude Deg	Min	Sec	Longitude Deg	Min	Sec	Township and Range Sec	Twp	Range	1/4 Sec	Feet From	Line	Feet From	Line	Indian Lands
41	37	45	087	08	41	29	37N	6W	SW	175	N	6	W	[ ] Yes [X] No

XIII. Attachments

(Complete the following questions on a separate sheet(s) and number accordingly; see instructions)
For Classes I, II, III, (and other classes) complete and submit on a separate sheet(s) Attachments A--U (pp 2-6) as appropriate. Attach maps where required. List attachments by letter which are applicable and are included with your application. A B C D F H I J K L M N O P Q R S T U (Additional Attachments V W)

XIV. Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

A. Name and Title *(Type or Print)*	B. Phone No. *(Area Code and No.)*
R. F. Chango, Vice President, Operations	(219) 787-3201
C. Signature: RF Chango	D. Date Signed: 3/22/99

EPA Form 7520-6 (Rev. 8-91)

Form Approved. OMB No. 2040-0042. Expires 6-30-98

EPA

United States Environmental Protection Agency

Underground Injection Control
Permit Application

(Collected under the authority of the Safe Drinking Water Act. Sections 1421, 1422, 40 CFR 144)

I. EPA ID Number IND003913423

	T/A	C
U		

Read Attached Instructions Before Starting

For Official Use Only

Application approved mo	day	year	Date received mo	day	year	Permit Number	Well ID	FINDS Number

II. Owner Name and Address			III. Operator Name and Address		
Owner Name: Bethlehem Steel Corp. , Inc. WAL/SPL-1			Operator Name: Bethlehem Steel Corp. , Inc. WAL/SPL-1		
Street Address: Burns Harbor Division PO Box 248		Phone Number: (219) 787-2712	Street Address: Burns Harbor Division PO Box 248		Phone Number: (219) 787-2712
City: Chesterton	State: IN	ZIP CODE: 46304	City: Chesterton	State: IN	ZIP CODE: 46304

IV. Commercial Facility	V. Ownership	VI. Legal Contact	VII. SIC Codes
[ ] Yes [X] No	[X] Private [ ] Federal [ ] Other	[X] Owner [ ] Operator	331

VIII. Well Status *(Mark "x")*

[ ] A. Operating	Date Started mo	day	year	[ ] B. Modification/Conversion	[X] C. Proposed

IX. Type of Permit Requested *(Mark "x" and specify if required)*

[X] A. Individual [ ] B. Area	Number of Existing Wells	Number of Proposed Wells	Name(s) of field(s) or project(s)
	3	1	

X. *Class and Type of Well (see reverse)*

A. Classes(es) (enter codes(s))	B. Type(s) (enter codes(s))	C. If class is "other" or type is code 'x,' explain	D. Number of wells per type (if area permit)
1	W		

XI. Location of Well(s) or Approximate Center of Field or Project / XII. Indian Lands (Mark 'x')

Latitude Deg	Min	Sec	Longitude Deg	Min	Sec	Township and Range Sec	Twp	Range	1/4 Sec	Feet From	Line	Feet From	Line	Indian Lands
41	37	45	087	08	41	29	37N	6W	SW	175	N	6	W	[ ] Yes [X] No

XIII. Attachments

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For Classes I, II, III, (and other classes) complete and submit on a separate sheet(s) Attachments A--U (pp 2-6) as appropriate. Attach maps where required. List attachments by letter which are applicable and are included with your application. A B C D F H I J K L M N O P Q R S T U (Additional Attachments V W)

XIV. Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

A. Name and Title *(Type or Print)*	B. Phone No. *(Area Code and No.)*
R. F. Chango, Vice President, Operations	(219) 787-3201
C. Signature: RF Chango	D. Date Signed: 3/22/99

EPA Form 7520-6 (Rev. 8-91)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC 20460

EPA

PLUGGING AND ABANDONMENT PLAN

NAME AND ADDRESS OF FACILITY	NAME AND ADDRESS OF OWNER/OPERATOR
Bethlehem Steel Corporation Burns Harbor Plant P O Box 248, Chesterton, IN 46304	Bethlehem Steel Corporation Burns Harbor Plant P O Box 248, Chesterton, IN 46304

LOCATE WELL AND OUTLINE UNIT ON SECTION PLAT — 640 ACRES

N / W / E / S

STATE	COUNTY	PERMIT NUMBER
IN	Porter	

SURFACE LOCATION DESCRIPTION
NW 1/4 of NW 1/4 of NW 1/4 of SW 1/4 of Section 29 Township 37N Range 6W

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

Surface Location 175 ft. from (N/S) N Line of quarter section
and 6 ft. from (E/W) W Line of quarter section

TYPE OF AUTHORIZATION	WELL ACTIVITY
☒ Individual Permit ☐ Area Permit ☐ Rule Number of Wells 1 Lease Name	☒ CLASS I ☐ CLASS II ☐ Brine Disposal ☐ Enhanced Recovery ☐ Hydrocarbon Storage ☐ CLASS III Well Number WAL/SPL-1

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT(LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
20"	106.5	240	240	30"
13-3/8"	54.5	1200	1200	17-1/2"
9-5/8"	40	2700	2700	12-1/4"
8-5/8" C-276		55	55	12-1/4"

METHOD OF EMPLACEMENT OF CEMENT PLUGS

☒ The Balance Method
☐ The Dump Bailer Method
☐ The Two-Plug Method
☐ Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	~~XXXXX~~	PLUG #3	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inches)	12-1/4	12-1/4,	9-5/8	9-5/8			
Depth to Bottom of Tubing or Drill Pipe (ft.)	4400	2787		2540			
Sacks of Cement To Be Used (each plug)	1119	845*		915			
Slurry Volume To Be Pumped (cu. ft.)	1320	113		1080			
Calculated Top of Plug (ft.)	2787	2540		3' Below grade			
Measured Top of Plug (if tagged ft.)	2787	2540		3' Below grade			
Slurry Wt. (Lb./Gal.)	15.6	12.6		15.6			
Type Cement or Other Material (Class III)	Class A	Resin		Class A			

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
2755'	4400'		

Estimated Cost to Plug Wells

$190,000

* gallons

CERTIFICATION

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

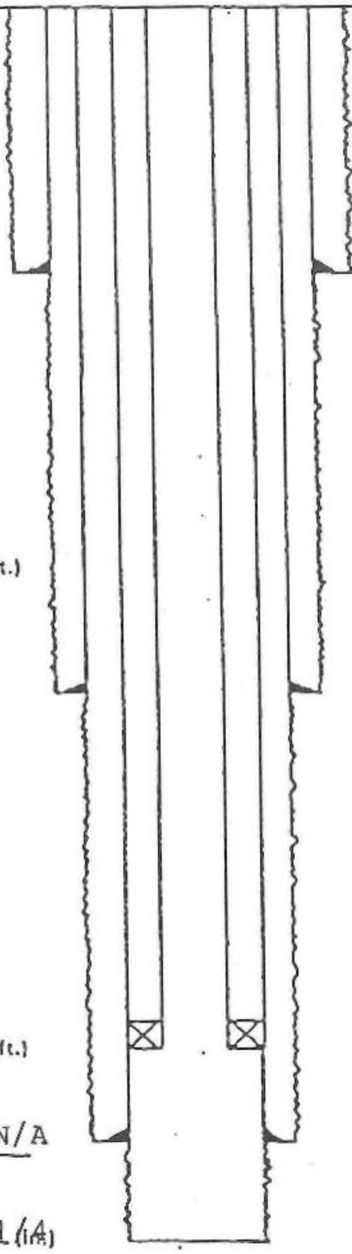
NAME AND OFFICIAL TITLE (Please type or print)	SIGNATURE	DATE SIGNED
R. F. Chango, Vice Pres., Operations	RF Chango	3/22/99

EPA Form 7520-14

ORIGINAL WELL CONSTRUCTION DURING OPERATION	PLUGGING AND ABANDONMENT CONSTRUCTION

ORIGINAL WELL CONSTRUCTION DURING OPERATION

Surface



Top Of Cement ____ (ft.) Surface

Surface Casing 200 (ft.)

USDW Base 726 (ft.)

Top Of Cement ____ (ft.) Surface

* Intermediate Casing 1200 (ft.)

Top Of Cement ____ (ft.) Surface

Packer Depth 2735 (ft.)

Perforations: N/A

Long String Casing 2755 (ft.)

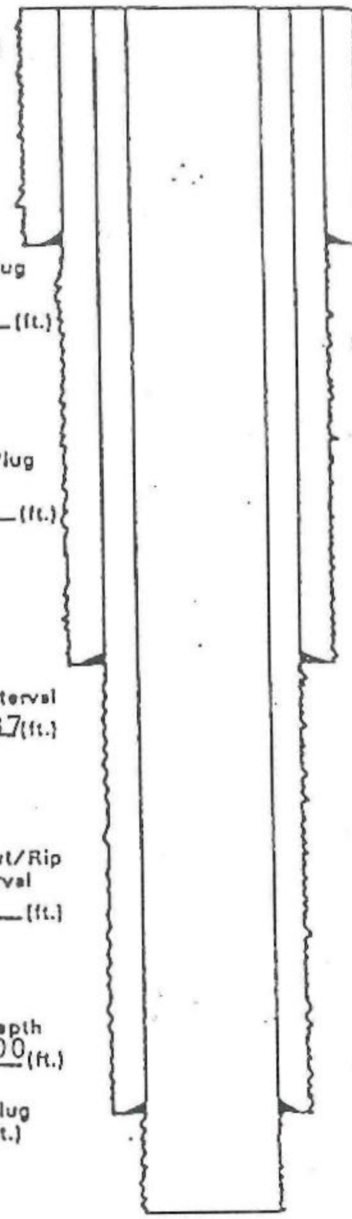
Hole Size 12-1/4 (in.)

* Depth 4400 (ft.)

** Add Any Additional Information
* May Not Apply

PLUGGING AND ABANDONMENT CONSTRUCTION

Surface



Top Plug Interval 3 (ft.) to 2540 (ft.)

Surface Casing 200 (ft.)

* USDW Base Plug Interval ____ (ft.) to ____ (ft.)

USDW Base 726 (ft.)

* Intermediate Cut/Rip Point Plug Interval ____ (ft.) to ____ (ft.)

* Intermediate Cut/Rip Depth ____ (ft.)

* Intermediate Casing 1200 (ft.)

* Middle Plug Interval 2540 (ft.) to 2787 (ft.)

* Long String Cut/Rip Point Plug Interval ____ (ft.) to ____ (ft.)

* Long String Cut/Rip Depth ____ (ft.)

Bottom Plug Depth 2787 (ft.) to 4400 (ft.)

* Mechanical Plug Depth ____ (ft.)

Long String Casing 2755 (ft.)

* Depth ____ (ft.)

** Add Any Additional Information
* May Not Apply

LIST OF ALL OPEN AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED

Specify Open Hole/Perforations/Varied Casing	From	To	Formation Name
Open hole 12-1/4"	2755	4400	Lower Mt. Simon

The information that is required to accompany the USEPA UIC Permit Application Form as attachments is contained in or referenced from this section. Certain data that is specific to the proposed WAL/SPL-1 well is provided in detail in this section while a significant volume of material that is common to all wells at the BSC Burns Harbor facility is referenced to the permit application materials submitted to the USEPA, Region 5 on October 15, 1997.

Material that is referenced to the "BSC 1997 UIC Permit Applications" refers to the document containing the following title that was enclosed with a certified letter from T.W. Easterly to N.M. Wiser, "Underground Injection Control (UIC) Permit Application Deficiencies, Bethlehem Steel Corporation, Burns Harbor Division", dated October 15, 1997.

UIC PERMIT RENEWAL APPLICATIONS

FOR

SPL-1 (PERMIT NUMBER IN-127-1W-0001)

WAL 1 (PERMIT NUMBER IN-127-1W-0003)

WAL-2 (PERMIT NUMBER IN-127-1W-0004)

for

BETHLEHEM STEEL CORPORATION, INC.

BURNS HARBOR DIVISION

OCTOBER 1997

VOLUMES NO. 1 AND NO. 2

ATTACHMENT A - AREA OF REVIEW METHODS

The area of review (AOR) methods are contained in the BSC 1997 UIC Permit Applications, Section A. An AOR of four (4.0) miles was used in the 1997 applications. Since the actual cone of influence for the BSC wells has been calculated to be between 3.0 and 3.8 miles, the 4.0 mile radius AOR is sufficient to take into account the proposed WAL/SPL-1 well location, which is less than 0.2 miles distant from existing WAL-1 and WAL-2.

ATTACHMENT B - MAPS OF WELL / AREA AND AREA OF REVIEW

The data required for this attachment is contained in the BSC 1997 UIC Permit Applications, Section B and in Appendices A-1 through A-5. Additionally, a map demonstrating the proposed location of WAL/SPL-1 in relation to the BSC plant infrastructure and WAL-1 is provided in this permitting document as Figure 3-1.

ATTACHMENT C - CORRECTIVE ACTION PLAN

Aside from Bethlehem's SPL-1, WAL-1, WAL-2 and the proposed WAL/SPL-1 well, there are only two wells within the four mile AOR that penetrate as deeply as the Bethlehem confining zone (upper Eau Claire shale). The Midwest Steel SPL-2 is a permitted active injection well injecting into the lower Mt. Simon Sandstone. The Midwest Steel SPL-1 was an injection well which injected into the Mt. Simon Sandstone and lower Eau Claire Formation prior to being converted into a monitoring well completed in the Galesville Sandstone. No corrective action plan for improperly constructed or unplugged wells is required since there are no known pathways for fluids to migrate from the Bethlehem injection zone upward toward USDWs.

ATTACHMENT D - HYDROGEOLOGY

The data required for this attachment is contained in the BSC 1997 UIC Permit Applications, Section D. Hydrogeology at the proposed location for WAL/SPL-1 is expected to be consistent with that existing in Bethlehem's other injection wells.

ATTACHMENT E - NAME AND DEPTH OF USDWs (Applicable to Class II Well Only)

ATTACHMENT F - GEOLOGY

The data required for this attachment is contained in the BSC 1997 UIC Permit Applications, Section F. Geology at the proposed location for WAL/SPL-1 is expected to be consistent with that existing at Bethlehem's other injection wells.

Cuttings samples will be collected and various geophysical logs and tests will be run during the installation of WAL/SPL-1. Data obtained during the drilling, completion and testing of the new well will be compared to the body of existing subsurface information to insure that it is consistent with that data utilized in predicting the capability of the local subsurface formations to safely accept and contain the injected waste fluids.

Based on electric and sample log profiles, core analysis data, scale, geometry, thickness and morphology, the injection zone and confining zone within the geological study area function as excellent injection and confining zones due to their:

1. Thick and sub-regionally continuous nature
2. Appropriate porosity and permeability characteristics
3. Large areal extent
4. Confinement above and below by thick, radially extensive, impermeable layers.
5. Total dissolved solids content above 10,000 ppm for reservoir fluids in the injection zone.
6. Absence of faulting to act as possible conduits for injected wastes out of the injection zone

ATTACHMENT G - GEOLOGICAL DATA ON INJECTION AND CONFINING ZONES

(Applicable to Class II Wells Only)

ATTACHMENT H - OPERATING DATA

Historical data concerning average and maximum daily rates and volumes, and average and maximum surface pressures for injection of WAL and SPL into Bethlehem's existing wells is contained in the BSC 1997 UIC Permit Applications, Section H. The operating parameters for proposed WAL/SPL-1 are expected to be similar to those of the existing injection wells at the BSC facility.

Since the proposed WAL/SPL-1 well is intended primarily as a backup, or alternate to the existing injection wells at Bethlehem's Burns Harbor Division, no additional waste disposal volumes or increased injection rates or pressures are being requested for this well, above what is already permitted for the facility.

Bethlehem is requesting that the maximum permitted waste ammonia liquor injection rates for WAL/SPL-1, WAL-1 and WAL-2 be maintained at a monthly average maximum level of 240 gallons per minute. This injection rate is to be calculated based on the combined total amount of WAL injected into both existing WAL wells and the proposed new WAL/SPL-1 well in a given month, divided by the combined total hours of WAL injection in that month.

Currently, there is no limitation on flow rate for injecting SPL at the Burns Harbor Division. There is however a maximum injection pressure limitation. Bethlehem is requesting that the injection rate for SPL into WAL/SPL-1 be limited only by a maximum surface injection pressure that will be calculated after the fracture gradient determination is performed during installation of the new well.

Bethlehem is requesting that the maximum permitted injection pressures for the proposed WAL/SPL-1 well be based on the results obtained from the injection interval fracture gradient determination that will be performed during installation. It is anticipated that the proposed fracture gradient determination will yield values that provide for maximum injection pressures equivalent to the currently permitted values for WAL and SPL of 977 psig and 699 psig, respectively.

Annulus Fluid Composition

The annulus fluid in WAL/SPL-1 (as is that in the other three Bethlehem wells) shall be composed of NaCl brine with corrosion inhibitor added. The seal pot and approximately the upper twenty feet of the annulus in the well will be filled with mineral oil to prevent freezing.

Source of Injected Fluids

Spent pickle liquor (hazardous waste code K062) results from the ultimate weakening of the hydrochloric acid solution utilized to clean scale and rust from steel during the finishing process.

Waste ammonia liquor is a by-product of making coke from coal, for use in steel making. Waste ammonia liquor is considered hazardous due to selenium, benzene and pyridine concentrations (hazardous waste codes D010, D018 and D038, respectively).

Chemical Analyses of Injected Fluids (All referenced tables are found in the BSC 1997 UIC Permit Applications

Table H-5 presents a summary of the results of numerous historical chemical analyses of the spent pickle liquor and the waste ammonia liquor. The table indicates the number of analyses for each constituent analyzed, and the mean, minimum and maximum values of the test results. Table H-6 contains the results of an Appendix IX parameter list analysis performed on the spent pickle liquor in 1993. Table H-7 contains the results of

ATTACHMENT I- FORMATION TESTING PROGRAM

USDW DETERMINATION

The lowermost USDW was verified by extensive formation fluid testing during the installation of the Galesville Sandstone monitor well at the Burns Harbor Division during 1995. The interface of the Silurian-Devonian and the top of the Marquoketa Shale is designated as the base of the lowermost USDW. No additional testing to determine the base of the USDW is planned during the installation of WAL/SPL-1.

FORMATION FLUID SAMPLING – PRESSURE DETERMINATION

The Galesville Sandstone monitor well is completed in the first porous and permeable formation overlying the confining zone. This well monitors formation pressure continuously and has been sampled periodically since late 1995. The well is currently sampled on a quarterly basis. Since formation fluid from this interval is regularly recovered and analyzed, no additional formation fluid sampling from the Galesville is planned during the installation of WAL/SPL-1.

Following the installation of the long string casing into the top of the Lower Mt. Simon Sandstone (injection interval), a formation fluid sample will be recovered by jetting or air lifting the well during the formation cleanup procedure. The well is being drilled and completed within the existing waste plume from Waste Ammonia Liquor (WAL) well #1 and WAL well #2. It is expected and understood that the fluid sample recovered from the Lower Mt. Simon Sandstone formation will be contaminated with WAL. Following stabilization of temperature, pH, and conductivity for the recovered fluids from the Lower Mt. Simon, a sample will be collected for laboratory analysis. The sample will be analyzed for the following parameters to characterize the formation fluid:

Acidity
Ammonia as N
Chloride
Total Cyanide
Total Phenols (4AAP)
pH
Total Dissolved Solids
Sulfate
Bicarbonate
Specific Gravity
Iron
Magnesium
Sodium
Calcium
Potassium
Benzene
Selenium
Pyridine

5. Thin Section Analysis
6. X-Ray Diffraction Analysis
7. Injection Reservoir Sand Sizing

Additional core analyses may be performed. Specific tests will be selected by the Burns Harbor facility geological consultant based on the evaluation of the whole cores and the open hole geophysical well logs obtained at that time.

INJECTION INTERVAL FRACTURE GRADIENT DETERMINATION

The procedure for conducting in-situ stress measurements within the Mt.Simon formation at the Burns Harbor facility is detailed below. A fracture test has been designed that will accurately determine the minimum principal stress which equals the fracture closure pressure. Downhole pressure gauges will be used in all testing to acquire accurate and interpretable data. Three intervals spaced over the majority of the open hole injection interval of the lower Mt. Simon formation are proposed for the testing. Three sections within the Mt. Simon will be selected for obtaining representative stress measurements throughout the interval and to have sufficient data if the recorded data at one or more of the stations proves unreliable due to downhole equipment failure or surface recording malfunctions.

The testing operations will be conducted during the drilling operations and prior to setting the 9-5/8-inch long string casing and 8-5/8-inch hastelloy casing extension and polished bore receptacle. The Mt. Simon injection interval is approximately 1,500 feet thick, and injection interval fracture gradient determination tests will be performed in the upper 500 feet, the middle 500 feet, and the lower 500 feet of the Mt. Simon Injection Interval. The anchor test method will entail drilling to a specified depth and then using only one packer to isolate the testing interval. After reaching a specified test depth, the drill string will be removed from the well and the anchor test assembly installed in the well on the drill string. The isolation packer will be set at the top of the proposed test interval. The test interval is limited to the drilled wellbore below the bottom set depth of the single isolation packer. This method eliminates the possibility of the lower isolation packer failing or breakdown occurring around the lower packer. If the anchor packer fails, the failure will be detectable on surface or by an increase in annular pressure above the test interval.

An increasing flow rate step test will be used to determine the fracture initiation pressure, fracture propagation pressure, and the fracture closure pressure during each of the three tests. Water will be used during the fracturing tests. A general testing procedure is presented below.

1. Required equipment will include an anchor test assembly, downhole memory gauge, surface recording downhole pressure gauge, flow meter, high pressure pump, wireline unit, and appropriate recording capabilities for flow rate and pressure.

approximately 2,800 feet. The bottom hole pressure and temperature will be monitored and recorded during the test.

Note: Wells WAL #1 and WAL #2 must be under either constant rate injection or shut in beginning not less than 12 hours prior to the WAL/SPL-1 testing. The operational status of these wells must be maintained constant throughout the WAL/SPL-1 test operations.

2. After recording approximately one hour of bottom hole pressure and temperature data to insure that the down hole gauges have stabilized, start injection of lake water to the well. A constant injection rate will be selected and maintained between 150 gpm and 300 gpm for the testing. The surface injection pressure at the wellhead will not exceed the permitted maximum injection pressure as calculated using the data from the fracture gradient determination. The constant rate injection period will be maintained for approximately 18 hours.
3. Stop injection to the well after approximately 18 hours of injection. Continue to monitor the bottom hole pressure and temperature during the falloff portion of the test. The falloff portion of the test is designed for approximately 24 hours
4. Continue monitoring the bottom hole pressure and temperature at approximately 2,800 feet until adequate data is collected. Pull out of the well with the logging tools and release the logging unit.

ATTACHMENT J – STIMULATION PROGRAM

Well stimulation will be performed following installation of the long string casing and before the performance of injectivity/falloff testing. The proposed well stimulation procedure is as follows:

A coiled tubing unit will be used for the well stimulation. The stimulation will include the following three steps:

Jetting with coiled tubing and nitrogen
Acid treatment through coiled tubing
Jetting with coiled tubing and nitrogen

The well will be jetted with coiled tubing and nitrogen before acidizing to remove as much drilling induced damage as possible. The well will also be jetted using nitrogen until stable samples of formation fluid are recovered from the formation. The pH, conductivity and temperature of the fluid recovered from the well will be monitored to determine when fluid from the well stabilizes. Based on the stimulation history of the Burns Harbor injection wells, the formation will be acidized with 10% hydrochloric (HCl) acid and regular strength mud acid (12% hydrochloric acid and 3% hydrofluoric acid). The formation will be acidized with approximately 9,000 gallons of 10% HCl acid and 10,000 gallons of mud acid. The acid treatment will be pumped in stages through the coiled tubing while working the coiled tubing up and down across the open hole interval.

The stimulation fluids, movable fines and solids will be removed from the well by jetting using coiled tubing and nitrogen. The well will be jetted until the formation fluids recovered from the well stabilize. The pH, conductivity and temperature of the fluid recovered from the well will be monitored to determine when fluid from the well stabilizes. Approximately 60,000 gallons of fluid will be recovered from the well.

The waste water generated during the jetting of the well will be transferred to a licensed hazardous waste disposal company for final disposal. Burns Harbor will dispose of any solids generated during the stimulation and jetting of the well by an appropriate method. The actual procedure that will be used is as follows:

STIMULATION PROCEDURE

1. Pick up an inflatable packer on the drill pipe. The inflatable packer will be run in the well on the drill pipe and set in the base of the Hastelloy casing PBR at about 2,755 feet. The drill pipe will be supported from slips on the surface. The drill rams on the blowout preventers will be closed on the drill pipe.
2. The annular space between the drill pipe and 9 5/8-inch casing will be filled with water. The annular space will be pressure tested to 1,000 psi to verify the setting of the inflatable packer.
3. Set up coiled tubing unit, fluid pumper and nitrogen pumper. The coiled tubing unit will be rigged up to run the coiled tubing through the drill pipe. Prepare to clean out the wellbore by commingling nitrogen and water down the coiled tubing.
4. Back flow the fluids from the well to frac tanks for storage. The frac tanks will be manifolded together for fluid storage. Establish good fluid returns to the frac tanks before going below 1,000 feet. Nitrogen and fresh water will be

an Appendix IX parameter list analysis performed on the waste ammonia liquor in 1993.

ATTACHMENT I - FORMATION TESTING PROGRAM

USDW DETERMINATION

The lowermost USDW was verified by extensive formation fluid testing during the installation of the Galesville Sandstone monitor well at the Burns Harbor Division during 1995. The interface of the Silurian-Devonian and the top of the Marquoketa Shale is designated as the base of the lowermost USDW. No additional testing to determine the base of the USDW is planned during the installation of WAL/SPL-1.

FORMATION FLUID SAMPLING - PRESSURE DETERMINATION

The Galesville Sandstone monitor well is completed in the first porous and permeable formation overlying the confining zone. This well monitors formation pressure continuously and has been sampled periodically since late 1995. The well is currently sampled on a quarterly basis. Since formation fluid from this interval is regularly recovered and analyzed, no additional formation fluid sampling from the Galesville is planned during the installation of WAL/SPL-1.

During installation of WAL/SPL-1 fluid sampling at a depth of approximately 2580 feet to 2620 feet will be performed in the 12-1/4" hole in the upper Mt. Simon Sandstone (within the containment interval portion of the injection zone). Following completion of the fracture gradient testing (discussed later), a straddle packer element will be utilized to isolate the 40 foot interval in the upper Mt. Simon and the drill pipe will be jetted with air or nitrogen to induce fluid flow to the surface. Following stabilization of temperature, pH, specific gravity and conductivity for the recovered fluids, a sample will be collected for laboratory analysis. The sample will be analyzed for the following parameters to characterize the formation fluid:

Acidity
Ammonia as N
Chloride
Total Cyanide
Total Phenols
pH
Total Dissolved Solids

Sulfate
TKN
Bicarbonate
Carbonate
Specific Gravity
Conductivity
Iron
Magnesium
Sodium
Calcium
potassium
strontium
Benzene
Naphthalene

This list of parameters is identical to that sampled from the Galesville Sandstone monitor well.

The fluid level in the drill pipe will be allowed to stabilize following the cessation of jetting or air lifting and the static fluid level will be determined. From this measurement and knowledge of the specific gravity of the fluid in the drill pipe, the formation pressure in the upper Mt. Simon Sandstone will be calculated.

Later in the well installation program, after the long string casing is set into the lower Mt. Simon Sandstone (injection interval), formation fluid will be recovered by jetting or airlifting the well during the formation clean procedure. Following stabilization of the recovered fluids based on temperature, pH, specific gravity and conductivity measurements at the surface, a fluid sample will be received for laboratory analysis. This sample will be analyzed for the same parameters as was the earlier sample from the upper Mt. Simon Sandstone.

CORE TESTING

No cores are planned to be recovered during the WAL/SPL-1 well installation since sufficient data is available from the Galesville Monitor Well and Midwest Steel injection wells.

INJECTION INTERVAL FRACTURE GRADIENT DETERMINATION

The procedure for conducting in-situ stress measurements within the Mt.Simon formation at the BSC facility is detailed below. A microfrac test has been designed that will accurately determine the minimum principal stress which equals the fracture closure pressure. Downhole shut-off and downhole pressure gauges will be used in all testing to acquire accurate and interpretable data. Three intervals spaced over the entire open hole injection interval of the lower Mt. Simon formation are proposed for the testing. These intervals will be chosen after evaluation of the open hole logs of the Mt. Simon injection interval. Multiple locations within the Mt. Simon will be selected for obtaining representative stress measurements throughout the interval and to have sufficient data if the recorded data at one or more of the stations proves unreliable due to downhole equipment failure or surface recording malfunctions.

The testing operations will be conducted after the completion of the drilling operations but prior to setting the 9-5/8-inch long string casing and 8-5/8-inch hastelloy casing extension and polished bore receptacle.

1. Required equipment will include a set of inflatable straddle packers, downhole memory gauge, downhole standing valve shut-off device, surface recording downhole pressure gauge, flow meter, high pressure/low volume pump, wireline unit, and appropriate recording capabilities for flow rate and pressure.

2. Run in the hole with the straddle packers on the drill pipe. The memory gauges will be located in a perforated sub below the lower packer.

3. Rig up a wireline unit and run a gamma ray log with casing collar locator through the drill pipe for depth control.

4. Set the straddle packers at the appropriate depth within the Mt. Simon.

5. Run in the hole with the surface readout bottomhole pressure gauge and standing valve and set in position at the standing valve seat.

6. Conduct a filtration test and determine the borehole leakoff rate. This data will be used to calculate the optimum pumping rate for in-situ stress measurements.

7. Constant rate injection into the straddled interval will be initiated at the rate calculated from the filtration test. The injection will be continued for a short period of time (typically 10-20 minutes). The total injection time is dependent on the total amount of the straddle interval thickness.

8. The minimum principal stress will be determined from the analysis of the pressure decline after shut-in.

9. Steps 7 and 8 will be repeated a minimum of three times at each test depth.

10. After confirmation that adequate analyzable data on the in-situ stresses has been acquired, pull the standing valve and surface readout gauges out of the drill pipe. Pull the drill pipe and straddle packers out of the hole. Release all equipment and proceed with the completion of the well.

INJECTIVITY / FALLOFF TESTING

Injectivity / falloff testing (ambient monitoring) will be performed after installation of the long string casing and well stimulation according to the following general procedures.

1. Move in logging unit and pump truck and set up to run an injectivity / falloff test. The test will be monitored with a surface readout bottomhole pressure and temperature gauge. The gauge will be set in the well at 3,500 feet. The bottom hole pressure and temperature during the testing will be monitored and recorded during the test.

   Note: Wells WAL #1 and WAL #2 must be under either constant rate injection or shut- in beginning not less than 12 hours prior to the WAL/SPL-1 testing. The operational status of these wells must be maintained throughout the WAL/SPL-1 test operations.

2. After recording approximately one hour of bottom hole pressure and temperature data to insure that the down hole gauges have stabilized, start injection of lake water to the well. A constant injection rate will be selected and maintained between

150 gpm and 300 gpm for the testing. The surface injection pressure at the wellhead will not exceed the permitted maximum injection pressure as calculated using the data from the fracture gradient determination. The constant rate injection period will be maintained for approximately 18 hours.

3. Stop injection to the well after approximately 18 hours of injection. Continue to monitor the bottom hole pressure and temperature during the falloff portion of the test. The falloff portion of the test is designed for approximately 24 hours.

4. Continue monitoring the bottom hole pressure and temperature at 3,500 feet until adequate data is collected. Pull out of the well with the logging tools and release the logging unit.

ATTACHMENT J - STIMULATION PROGRAM

Well stimulation will be performed following installation of the long string casing and before the performance of injectivity / falloff testing. The proposed well stimulation procedure is as follows:

A coiled tubing unit will be used for the well stimulation. The stimulation will include the following tree steps:

Jetting with coiled tubing and nitrogen
Acid treatment through coiled tubing
Jetting with coiled tubing and nitrogen

The well will be jetted with coiled tubing and nitrogen before acidizing to remove as much drilling induced damage as possible. The well will also be jetted using nitrogen until stable samples of formation fluid are recovered from the formation. The pH, specific gravity, conductivity and temperature of the fluid recovered from the well will be monitored to determine when fluid from the well stabilizes. After stabilization, 20 gallons of fluid from the formation will be collected for laboratory analysis. The fluid will be analyzed for the same parameters as the sample collected earlier from the upper Mt. Simon Sandstone (Galesville Monitor Well parameter list). The large sample is required since it may be used later to conduct compatibility testing with WAL and SPL. A minimum of 40,000 gallons of fluid will be jetted from the well before collecting the sample.

Based on the stimulation history of the BSC injection wells, the formation will be acidized with 10% hydrochloric (HCl) acid and regular strength mud acid (12% hydrochloric acid and 3% hydrofluoric acid). The formation will be acidized with approximately 9,000 gallons of 10% HCl acid and 10,000 gallons of mud acid. The acid treatment will be pumped in stages through the coiled tubing while working the coiled tubing up and down across the open holed interval.

The stimulation fluids, movable fines and solids will be removed from the well by jetting using coiled tubing and nitrogen. The well will be jetted until the formation fluids recovered from the well stabilize. The pH, specific gravity, conductivity and temperature of the fluid recovered from the well will be monitored to determine when fluid from the well stabilizes. Approximately 60,000 gallons of fluid will be recovered from the well.

The waste water generated during the jetting of the well will be transferred to a licensed hazardous waste disposal company for final disposal. BSC will dispose of any solids generated during the simulation and jetting of the well by an appropriate method. The actual procedure that will be used is as follows:

STIMULATION PROCEDURE

1. Pick up an inflatable packer on the drill pipe. The inflatable packer will be run in the well on the drill pipe and set in the base of the Hastelloy casing PBR at about 2755 feet. The drill pipe will be supported from slips on surface. The drill rams on the blowout preventers will be closed on the drill pipe.
2. The annular space between the drill pipe and 9-5/8-inch casing will be filled with water. The annular space will be pressure tested to 1,000 psi to verify the setting of the inflatable packer.
3. Set up coiled tubing unit, fluid pumper and nitrogen pumper. The coiled tubing unit will be rigged up to run the coiled tubing through the drill pipe. Prepare to clean out the wellbore by commingling nitrogen and water down the coiled tubing.
4. Back flow the fluid from the well to frac tanks for storage. The frac tanks will be manifolded together for fluid storage. Establish good fluid returns to the frac tanks before going below 1000 feet. Nitrogen and fresh water will be commingled down the coiled tubing if necessary to remove the solids from the wellbore. The fill or soilds from the wellbore will be removed to total depth. The well will be jetted until the returns are sufficiently clean to stop the jetting.

5. After the fill is removed from the wellbore and the returns cleanup, stop pumping nitrogen and continue pumping fresh water. Flush the coiled tubing and well casings with fresh water.

   NOTE: The waste water and spent acid treatment fluids recovered from the well clean out will be disposed of by transferring to a licensed disposal company.

6. The open hole injection interval will be acidized through coiled tubing with approximately 9,000 gallons of 10% HCl acid and approximately 10,000 gallons of mud acid (12% HCl acid and 3% hydrofluoric acid).
7. Displace acid out of coiled tubing with one coiled tubing volume of fresh water. Allow the acid to soak for approximately one (1) hour.
8. Displace acid out of the wellbore and into the formation with fresh water by pumping down both the coiled tubing and drill pipe.
9. Prepare surface equipment to jet the well back to frac tanks using coiled tubing and nitrogen. The frac tanks will be manifolded together for fluid storage.
10. Go in the well with the coiled tubing pumping nitrogen at approximately 300 SCFM through the coiled tubing. Establish good fluid returns to the frac tanks before going below 1,000 feet. Back flow fluid recovered to frac tanks while running in the well with the coiled tubing to the total depth. The well will be jetted for approximately 12 hours or until the returns cleanup.
11. Continue back flowing the well using coiled tubing and nitrogen. After the returns from well clean up or the waste water storage limit is reached, stop pumping nitrogen and switch to pumping fresh water down the coiled tubing. Circulate the well until all of the nitrogen is circulated out. Check for fill in the wellbore. Pull out of the hole with the coiled tubing.
12. Cleanup location and release the stimulation equipment. The waste water and spent acid treatment fluids recovered from the well clean out will be disposed of by transferring to a licensed disposal company for final disposal.
13. Release the inflatable packer. Pull out of the well with the drill pipe and inflatable packer.
14. Cleanup and release, frac tanks, hoses and pumps.

ATTACHMENT K - INJECTION PROCEDURES

WAL and SPL are generated and treated prior to injection as described in the BSC 1997 UIC Permit Applications, Section K. Appropriate piping and controls will be added to the system to bring the WAL or SPL to the WAL/SPL-1 well.

An additional filtering stage has been added to the SPL surface facilities (Note: the new filter system was not included in the BSC 1997 UIC Permit Applications). In an attempt to limit formation damage in the injection interval, a new polishing filter consisting of a Hayward polypropylene tri-plexed sock filter housing, utilizing 1 micron filter bags, has been added to the SPL flow line down stream of the leaf filters. All control valves are constructed of CPVC with viton seals. This filter unit is intended to capture any diatomaceous earth pre-coat, or other particulate materials that bypass the leaf filters prior to entering the injection wells. Figure 3-2 is a diagram of the new filtering unit. Figure 3-3 demonstrates the location of the new filter unit in the SPL treatment system. For injection of SPL into the proposed WAL/SPL-1 well, the SPL will be transported via rail or truck, after filtering, to the location of the well.

WAL/SPL-1 will utilize a seal pot system, pressurized with a nitrogen blanket, to maintain the required pressure on the annulus between the injection tubing and the well casing strings. Annulus pressure is continuously monitored and recorded. All other BSC injection wells operate in this manner. Data may be recorded digitally by a computerized system.

Bethlehem Steel will utilize automatic alarms and automatic shutdowns on the WAL/SPL-1 well in case of high injection pressure, low annulus pressure or low annulus vs injection pressure differential.

Proposed WAL/SPL-1 will be designed to handle injection of both WAL and SPL. However, when the well is in service it is expected that either WAL or SPL will be injected for relatively long continuous periods of time. The well will not be switched back and forth rapidly between the two waste streams. A buffer of fresh water will be injected between changes in injectate stream from WAL to SPL in order to minimize direct mixing in the injection interval formation.

ISG Burns Harbor, LLC.
Pre-Draft UIC Permit Nos. IN-127-1W-0001, 0003, 0004 and 0007

Attachment 8 - Injection Procedures

ATTACHMENT N - CHANGES IN INJECTION FLUID (Applies to Class III Wells Only)

ATTACHMENT O - PLANS FOR WELL FAILURES

In order to protect human health and the environment, mechanical integrity of a waste injection well must be maintained. In the event that a loss of mechanical integrity is suspected by the operator the following steps will be implemented for all Bethlehem injection wells.

1. The operator will immediately begin to safely shut in the well using the normal shut down procedure.

2. The operator will notify designated Bethlehem Steel personnel of the suspected well failure and shut down.

3. The designated Bethlehem Steel personnel will be responsible for notification of Federal and State regulatory agencies as required by the well permit.

4. The United States Environmental Protection Agency, Region 5, will be notified of the suspected well failure and resultant shut down as required by permit conditions.

5. The mode of well failure will be identified.

6. A remedial plan will be prepared to determine what investigations and actions will be undertaken.

7. The remedial plan will be submitted to Federal and State regulatory agencies for approval before beginning any remedial action.

8. Upon authorization, the remedial plan will be implemented.

ALTERNATE DISPOSAL OR STORAGE

In case of well failure while injecting WAL, either WAL-1 or WAL-2 is available for injection service as a backup.

In case of well failure while injecting SPL, SPL-1 will either be available for injection or spent pickle liquor will be stored on site (if possible), transferred to a truck loading station for sale as a substitute for a commercial product, or shipped off site for proper disposal.

ATTACHMENT P - MONITORING PROGRAM

Monitoring for the WAL/SPL-1 well will be carried out in the same manner as that described for SPL-1 in the BSC 1997 UIC Permit Applications, Section P.

ATTACHMENT Q - PLUGGING AND ABANDONMENT / POST CLOSURE CARE PLANS

The plugging and abandonment plan for the WAL/SPL-1 well is as follows.

<u>WAL/SPL-1</u>

<u>Permit No. IN-(to be assigned)</u>

1. Obtain approval from the regulatory agency prior to commencing operations. Conduct the required mechanical integrity testing and ambient monitoring testing and submit the test data to the regulatory agency.
2. Move in and rig up a workover rig.
3. Flush the wellbore with water. The total flush volume will be a minimum of three wellbore volumes.
4. Dismantle the wellhead and install blowout preventers.
5. Remove the injection tubing and seal assembly.
6. Place Class "A" cement in the openhole interval from the top of fill to 2,787 feet. The cement will be balanced in place in stages.
7. Place acid resistant cement from the top of the Class "A" plug to the bottom of the Eau Claire formation at approximately 2540 feet.
8. Wait on cement for 48 hours.
9. Fill the casing (9-5/8-inch casing) from the top of the acid resistant cement to 3 feet below the surface with Class "A" cement. . This top plug will be pumped in 500-1,000 feet stages and balanced in place. An appropriate length of the workstring will be pulled and laid down. The workstring will be reversed circulated to confirm that it is still in cement from the previous stage and the process will be repeated until the cement is 3 feet below the surface.
10. Rig down and move out the workover equipment.

11. Wait on cement for at least eight hours.

12. Cut off the casing 3 feet below ground level. Weld a steel plate on top of the casing. The steel plate should be inscribed with the following information:

    Bethlehem Steel Corporation
    WAL/SPL-1
    Permit No. IN- (to be assigned)
    P& A ____.

COST ESTIMATE FOR PLUGGING AND ABANDONMENT OF WAL/SPL-1

The estimated cost for plugging and abandoning the proposed new well is $190,000.

POST CLOSURE CARE PLAN

The procedures for post closure care described herein are to be initiated upon permanent cessation of injection, and closure (plugging and abandonment) of Bethlehem Steel's Injection Well , WAL/SPL-1, at the Burns Harbor Division in northern Indiana. This procedure is in accordance with the requirements of 40 CFR 146.72 regarding post-closure. Any proposed significant revisions to this plan over the life of the well will be submitted not latter than the date of the closure report required under 40 CFR 146.71 (a) (7) (c).

The following information is a required part of the post closure plan:

1) Pressure in the injection zone before injection began:

The original pressure in the injection zone prior to the initiation of injection activities was measured during the construction of each existing BSC well. The pre-injection pressures for Bethlehem's existing wells were as follows:

Well	Pressure (psi)	Depth(ft)	Gradient (psi/ft)	
SPL-1	1365	3250	0.42	=1153@2745'
WAL-1	1429	3402	0.42	
WAL-2	1432	3410	0.4199	

The pre-injection pressure in the injection zone at a depth of 2180 ft would be 915.5 psi. Static reservoir pressure will be measured in WAL/SPL-1 during the completion of the well. A static pressure will be measured after an appropriate amount of stabilization time after completion of drilling.

2) Anticipated pressure in the injection zone at the time of closure:

Modeling performed for the Bethlehem petition demonstration indicated the maximum pressure increase in the injection zone following a twenty year future operational period at maximum rates and pressures would be 300 psi (Intera Technologies Modeling Report, Figure-7). Therefore, the anticipated pressure in the injection zone in the year 2007 is expected to be approximately 1215.5 psi at a depth of 2180 feet.

3) The predicted time until pressure in the injection zone decays to the point that the well's cone of influence no longer intersects the base of the lowermost USDW:

Pressure decay in SPL-1 is nearly instantaneous following well shut down, therefore the decay time will be calculated based on the WAL wells.

From the time injection ceases, it is expected to take approximately 70.89 hours until the cone of influence from the WAL wells no longer exists. This is based on the same assumption used in the petition modeling, that all waste ammonia liquor in the past and future, is injected into a single well.

The injection induced reservoir pressure after injection ceases can be described by the following equation:

$$\Delta p = 162.6 \frac{qu}{kh} \log\left(\frac{t_p + \Delta t}{\Delta t}\right)$$

rearranging:

$$\Delta t = \frac{t_p}{antilog\left(\frac{\Delta p}{162.6\,q}\ \frac{kh}{\mu}\right) - 1}$$

where:

t_p	=	pseudo-injection time of 256,045 hours (10,669 days)
Δp	=	106 psi reservoir pressure increase required to cause a cone of influence to exist (from petition modeling)
q	=	maximum WAL injection rate of 8,229 barrels/day (240 gpm)
$\frac{kh}{\mu}$	=	44,908 md-ft/cp (transmissivity product from March, 1996 WAL-1 test)

$$\Delta t = \frac{256{,}045}{antilog\left(\dfrac{106}{162.6 \times 8{,}229} \quad 44{,}908\right) - 1} = 70.89\,hours = 2.95\ days$$

The pseudo-injection time includes the historical period which encompasses both injection (at various rates) and shut-in periods, and the future injection period at an assumed constant rate. The pseudo-injection time that represents the end of the year 2007 is calculated as follows:

$$\frac{Historical\ Volume\ +\ Future\ Volume}{Final\ Stabilized\ Injection\ Rate} = \frac{V_H + V_F}{Q}$$

Historical injection volumes through October 7, 1997 for Bethlehem's wells are as follows:

WAL-1	1,000,238,386 gallons
WAL-2	1,231,619,909 gallons
SPL-1	162,218,793 gallons
Total	2,394,077,088 gallons

where:

V_H	=	2,394,077,088 gallons through October 7, 1997 (for added conservatism, this assumes that all WAL *and SPL* historical volumes had been injected into a single well)
V_F	=	1,292,976,000 gallons October, 1997 through December 31, 2007 at a continuous 240 gallons per minute rate
Q	=	240 gals/min x 60 min/hr (permitted maximum rate) = 14,400 gallons per hour

$$\frac{2{,}394{,}077{,}088 + 1{,}292{,}976{,}000}{14{,}400} = 256{,}045\ \textit{hours} = 10{,}669\ \textit{days}$$

4) Predicted position of the waste front at closure:

The predicted position of the waste front at the time of well closure (the year 2007 in the Bethlehem petition demonstration) is approximately 2344 feet from the WAL wells and 1295 feet from SPL-1 (Intera Technologies Modeling Report, Table-14).

5) Status of any cleanups required under 40 CFR 146.64:

The cited regulation concerns corrective actions for wells within the area-of-review. No corrective actions are currently underway or planned within the Bethlehem Steel AOR

6) Estimated costs of post closure care:

The estimated costs of post closure care are $2,500.

Upon closure of any of Bethlehem Steel's injection wells , Bethlehem shall:

1) Continue and complete any cleanup action required under 40 CFR 146.64, if applicable.

2) Continue post closure maintenance and monitoring of any ground water monitoring wells required under the applicable permits until pressure in the injection zone decays to the point that the injection well's cone of influence no longer intersects the base of the lowermost USDW (top of the Marquoketa Shale).

3) Submit a survey plat map to the local zoning authority designated by the Director, and to the Regional Administrator of the Region 5 USEPA office. The survey plat map shall indicate the location of the closed well relative to permanently surveyed benchmarks.

4) Provide appropriate notification and information to state and local authorities that have cognizance over drilling activities to enable them to impose such appropriate conditions on subsequent drilling activities that may penetrate the well's confining or injection zone.

5) Retain, for a period of three years following well closure, records reflecting the nature, composition and volume of all injected fluids. The Director shall require Bethlehem Steel to deliver the records to the Director at the conclusion of the retention period, and the records shall thereafter be retained at a location designated by the Director for that purpose.

6) Upon closure of the well in accordance with the approved closure plan, Bethlehem Steel shall record a notation on the deed to the facility property, or on some other instrument that is normally examined during title search, that will in perpetuity provide any potential purchaser of the property with the following information:

   a) The fact that the land has been used to manage and dispose hazardous waste(s) in deep wells,

   b) The name(s) of the state agencies and/or local authorities with which the survey plat map was filed, and the address of the regional USEPA office to which it was submitted.

   c) The type and volume of waste injected, the injection interval or intervals into which it was injected, the name(s) of the generator(s) of the waste and the time period over which the injection occurred.

Bethlehem Steel shall comply with the post closure financial assurance requirements of 40 CFR 146.73, and acknowledges that the obligation to maintain financial responsibility for post closure care survives the termination of the UIC Permit(s) or the cessation of injection.

ATTACHMENT R - NECESSARY RESOURCES

The plugging and abandonment cost estimates for Bethlehem Steel's injection wells as of February 1999 are as follows:

SPL-1	$166,900	
WAL-1	$96,900	
WAL-2	$96,900	
WAL/SPL-1	$190,000	(proposed well)

Additionally, the February1999 cost estimate for plugging and abandoning the Galesville Sandstone Groundwater Monitoring Well is $89,300. Documentation regarding how these values were calculated is included in Appendix B.

Based on the above, a total of $450,000 is required to plug and abandon the three existing injection wells and the deep groundwater monitoring well. Bethlehem currently has in place a trust agreement with a 1998 value of $463,748 to cover the plugging and abandonment costs of the existing wells. As stated in the BSC 1997 UIC Permit Applications, Section R and Appendix D, Bethlehem wishes to replace the existing trust agreement with an alternative financial assurance mechanism as provided under 40 CFR Section 144.63.

Prior to permit issuance, Bethlehem will define the desired alternative mechanism, including the financial test and corporate guarantee for plugging and abandonment alternative. The selected mechanism will be used for all the existing injection wells, the proposed WAL/SPL-1 well and the Galesville Sandstone Groundwater Monitor well and will cover the total projected plugging and abandonment costs of $640,000.

ATTACHMENT S - AQUIFER EXEMPTIONS (Not applicable at BSC)

ATTACHMENT T - EXISTING EPA PERMITS

A summary of past and existing environmental permits for the Bethlehem Steel Burns Harbor Division facility were included in the BSC 1997 UIC Permit Applications, Section T and Table T-1. That tabulation remains current.

ATTACHMENT U - DESCRIPTION OF BUSINESS

The information required for inclusion in this attachment was provided in the BSC 1997 UIC Permit Applications, Section U. That material remains current.

ATTACHMENT V - PRIOR RELEASES

(from USEPA Region 5 Michigan / Indiana Permit Application Checklist for Class I Injection Wells)

Requested maximum permitted surface injection pressures for WAL/SPL-1 are to be based on the fracture gradient testing that will be performed during installation of the well. The new well is to be constructed for injection into the lower Mt. Simon Sandstone, below the B-Cap Shale.

The BSC 1997 UIC Permit Applications documented in Section V injection pressure information for the existing BSC injection wells.

Between 1963 and 1986, SPL-1 was completed to inject into the Lower Eau Claire Formation and the entire thickness of the Mt. Simon. Following a 1986 recompletion, the well has injected only into the lower Mt. Simon Sandstone, below the B-Cap Shale. The lower Mt. Simon, below the B-Cap Shale is the injection interval requested in this permit application for WAL/SPL-1.

Between 1968 and 1990, WAL-1 and WAL-2 were completed to inject into the entire thickness of the Mt. Simon. Following a 1990 recompletion, the wells have injected only into the lower Mt. Simon Sandstone, below the B-Cap Shale. The lower Mt. Simon, below the B-Cap Shale is the injection interval requested in this permit application for WAL/SPL-1.

No releases of injectate from any of the Bethlehem Steel injection wells are known to have occurred into non-permitted intervals.

ATTACHMENT W - ADDITIONAL INFORMATION

(from USEPA Region 5 Michigan / Indiana Permit Application Checklist for Class I Injection Wells)

The proposed new well, WAL/SPL-1, will inject hazardous waste with the listed Waste Code K062 (Spent Pickle Liquor from iron and steel production). The well will also inject waste ammonia liquor which is characteristically hazardous (toxic) due to selenium, benzene and pyridine concentration (Waste Codes D010, D018 and D038, respectively).

The Land Disposal Restriction deadline for waste ammonia liquor which contains selenium was May 8, 1990. The Land Disposal Restriction deadline for Spent Pickle Liquor was August 8, 1990. The ban on benzene and pyridine was effective for deep well injection on April 8, 1998.

The Bethlehem Steel Burns Harbor Division has an approved petition for exemption from the land disposal restrictions on hazardous waste injection under the Hazardous and Solid Waste Amendments to RCRA pursuant to the regulations set forth at 40 CFR Part 148. The exemption was effective on August 1, 1990. A petition modification in 1993 included the benzene contained in the waste ammonia liquor stream under the exemption. A modification in 1998 included the pyridine contained in the waste ammonia liquor stream under the exemption. Bethlehem Steel continues to operate its injection wells in compliance with the exemption conditions.

During the installation of WAL/SPL-1 testing will be performed to gather additional data to support that information already included in the petition demonstration. A significant test will involve the determination of the site specific fracture gradient pressure in the lower Mt. Simon Formation (injection interval).

WASTE MINIMIZATION

A significant proportion of the spent pickle liquor generated during the finishing of steel products is sold commercially. Only that portion that cannot be sold is to be injected into SPL-1 or proposed WAL/SPL-1. Bethlehem continues to try and expand the market for its spent pickle liquor in order to minimize underground injection volumes. In addition, Bethlehem is currently exploring alternative recycling options for SPL, including hydrochloric acid regeneration. It is anticipated that an alternative recycling option will be in place at the time the proposed well is constructed.

Coke oven gases and waste ammonia liquor generated during the production of coke from coal is subjected to several rounds of recycling and processing to reduce its overall volume. A principal contaminate in coke oven gas, ammonia, is largely removed from the process stream by scrubbing with sulfuric acid to form ammonia sulfate, which is crystallized, recovered and sold as a by product. Gases from the coke ovens that contain light hydrocarbon fractions are primarily burned as fuel within the plant.

Excess water is evolved from coal during the coking process. Following several recirculations through the coke oven gas cooling system, excess liquids are removed from the circulation system for further treatment, or disposal through the WAL or proposed WAL/SPL-1 wells.

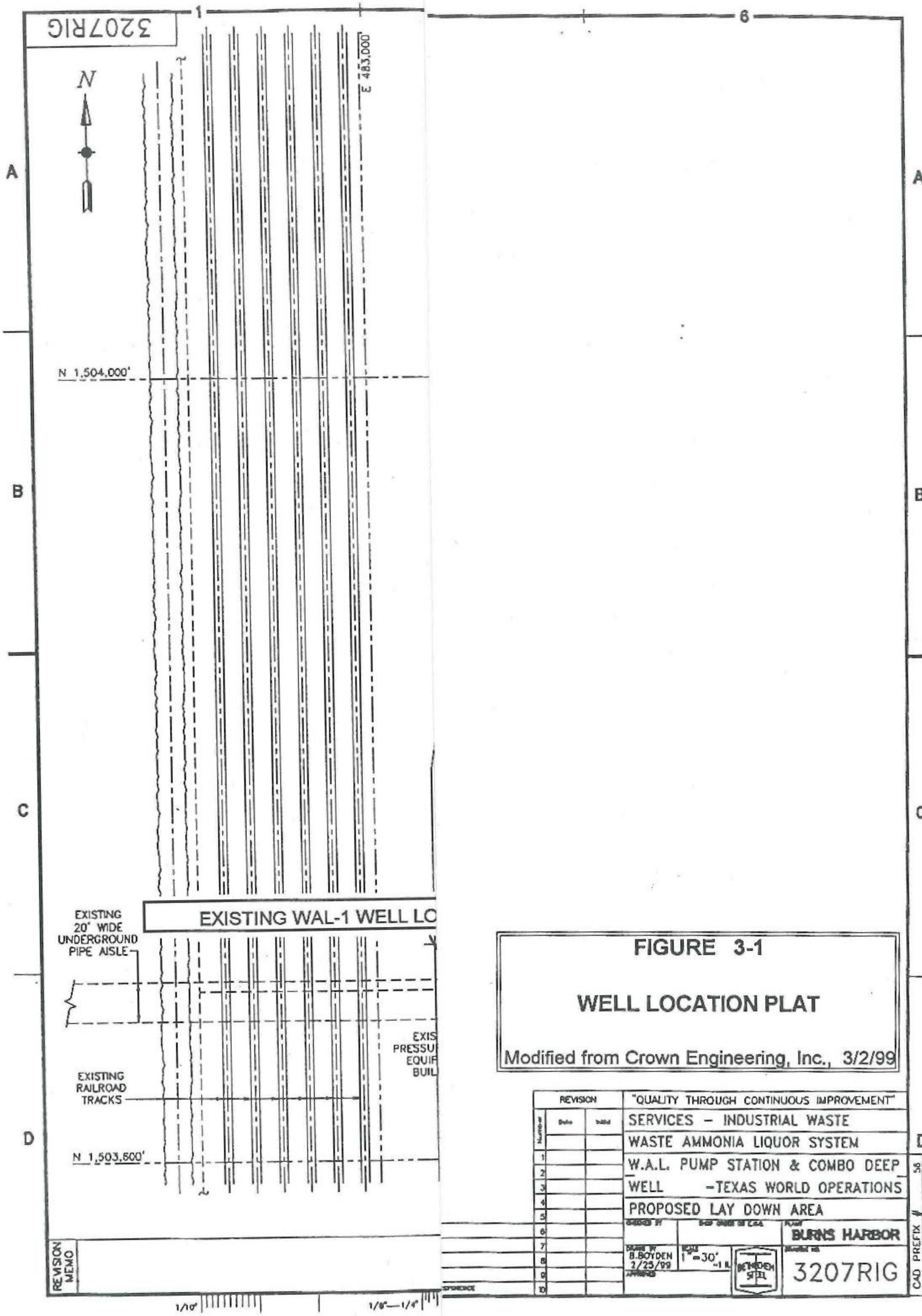


FIGURE 3-1

WELL LOCATION PLAT

Modified from Crown Engineering, Inc., 3/2/99

ALL VALVES CPVC WITH VITON SEALS
PIPING CPVC SCHEDULE 80
FIBERGLASS BASE
ALL BOLTING 300 SERIES STAINLESS STEEL
FILTERS GLASS COUPLED POLYPRO

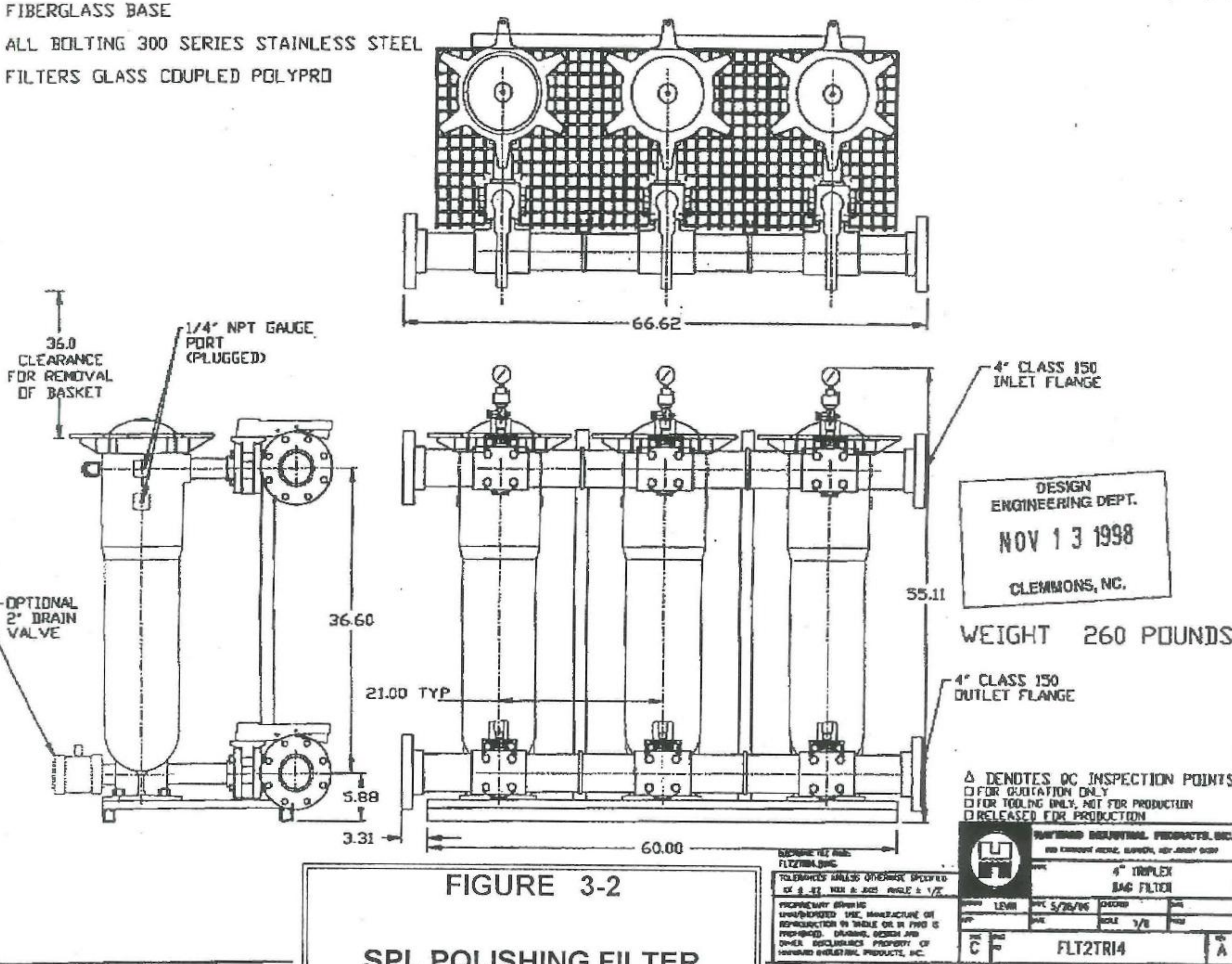
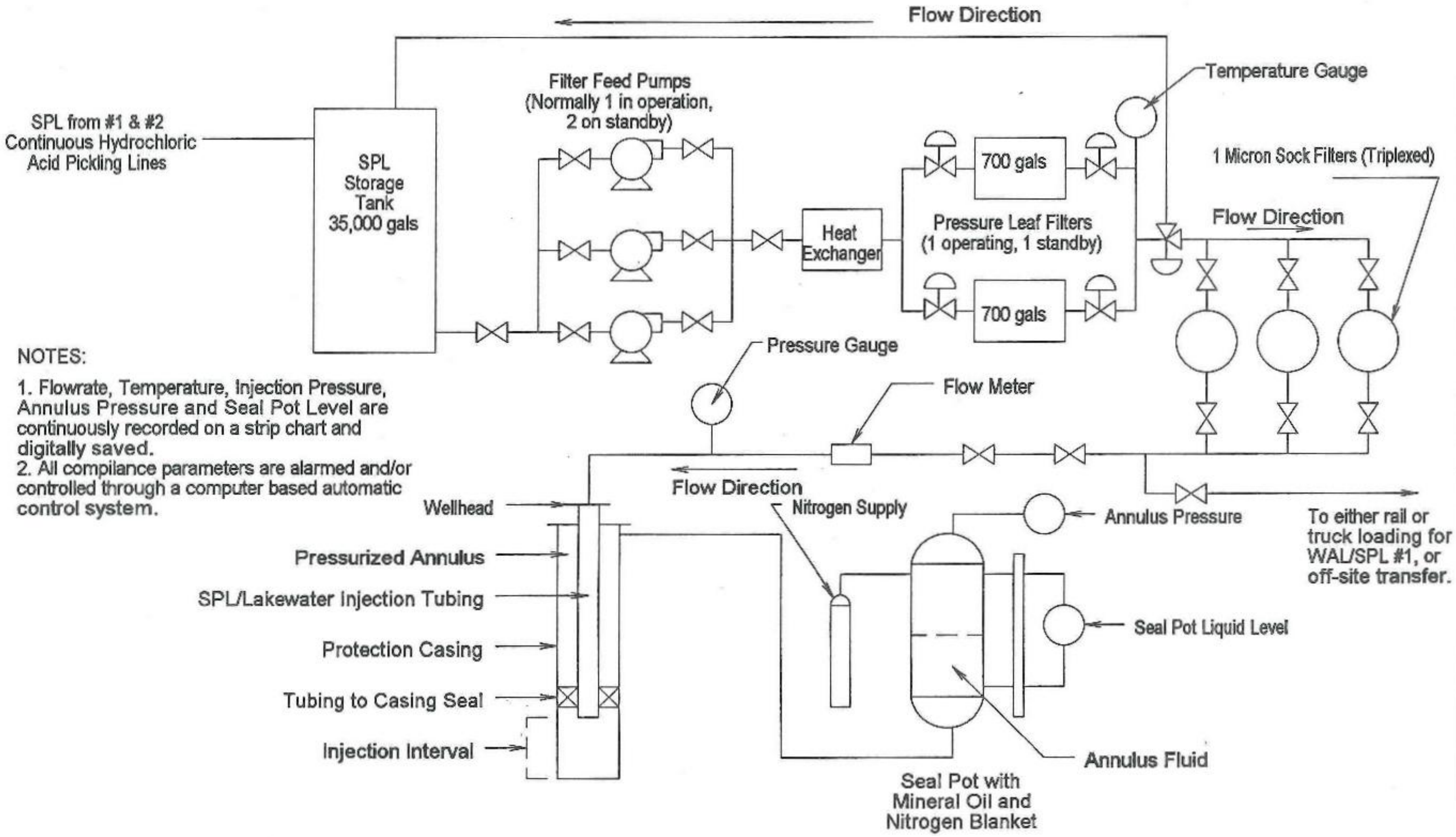


FIGURE 3-2

SPL POLISHING FILTER

SPL TREATMENT SCHEMATIC



NOTES:

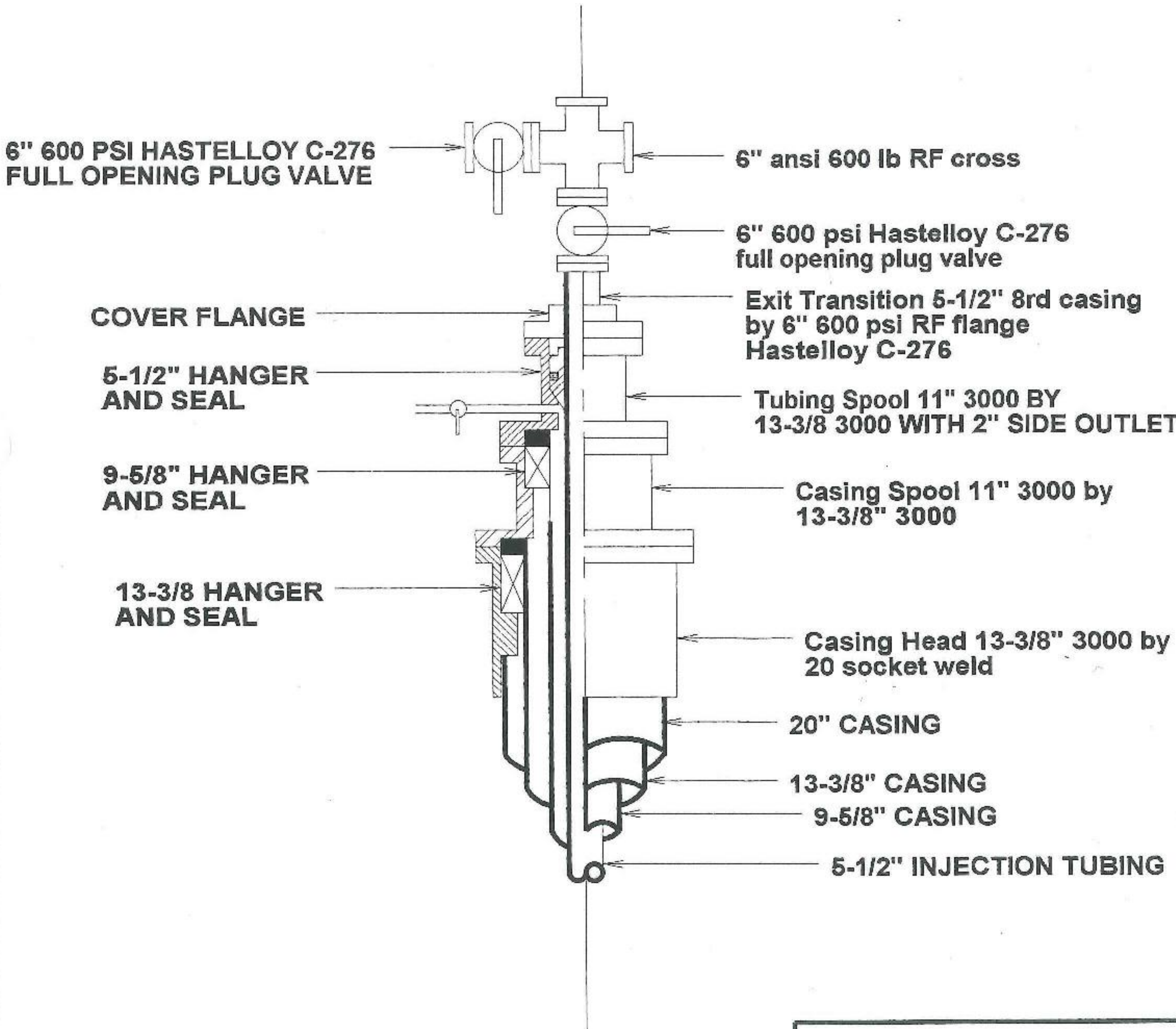
1. Flowrate, Temperature, Injection Pressure, Annulus Pressure and Seal Pot Level are continuously recorded on a strip chart and digitally saved.
2. All compilance parameters are alarmed and/or controlled through a computer based automatic control system.

TEXAS WORLD OPERATIONS HOUSTON, TX		
BSC, SPL TREATMENT SCHEMATIC		
DR BY: RFW & JES	03/18/99	REV:2

FIGURE 3-3

FIGURE 3-5

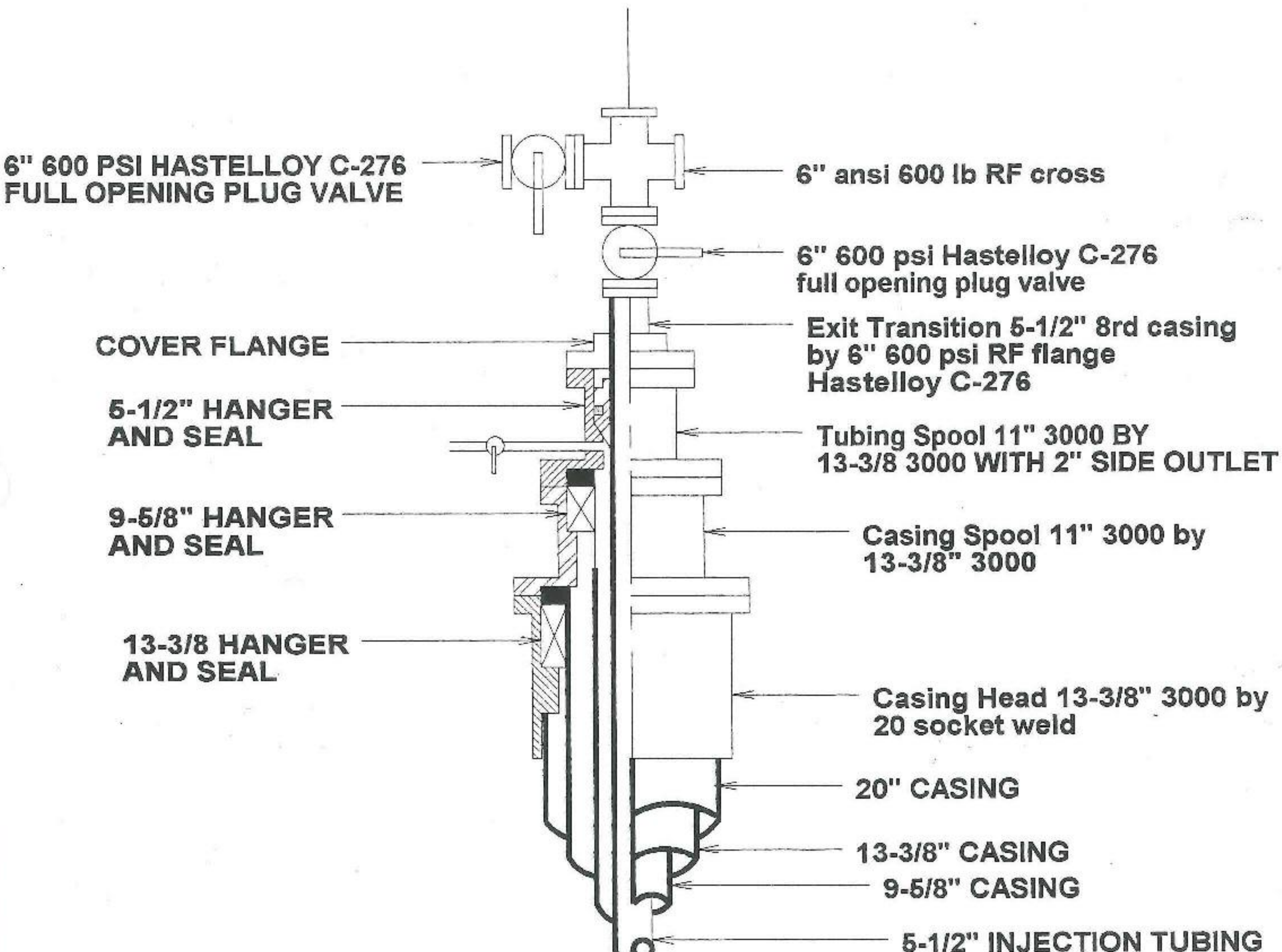
BETHLEHEM STEEL CORPORATION
BURNS HARBOR DIVISION
WELL HEAD WAL/SPL -1



TEXAS WORLD OPERATIONS HOUSTON, TX		
BETHLEHEM STEEL COPR. WAL/SPL-1		
DR. BY RFW	02/26/99	REV:0

FIGURE 3-5

BETHLEHEM STEEL CORPORATION
BURNS HARBOR DIVISION
WELL HEAD WAL/SPL -1



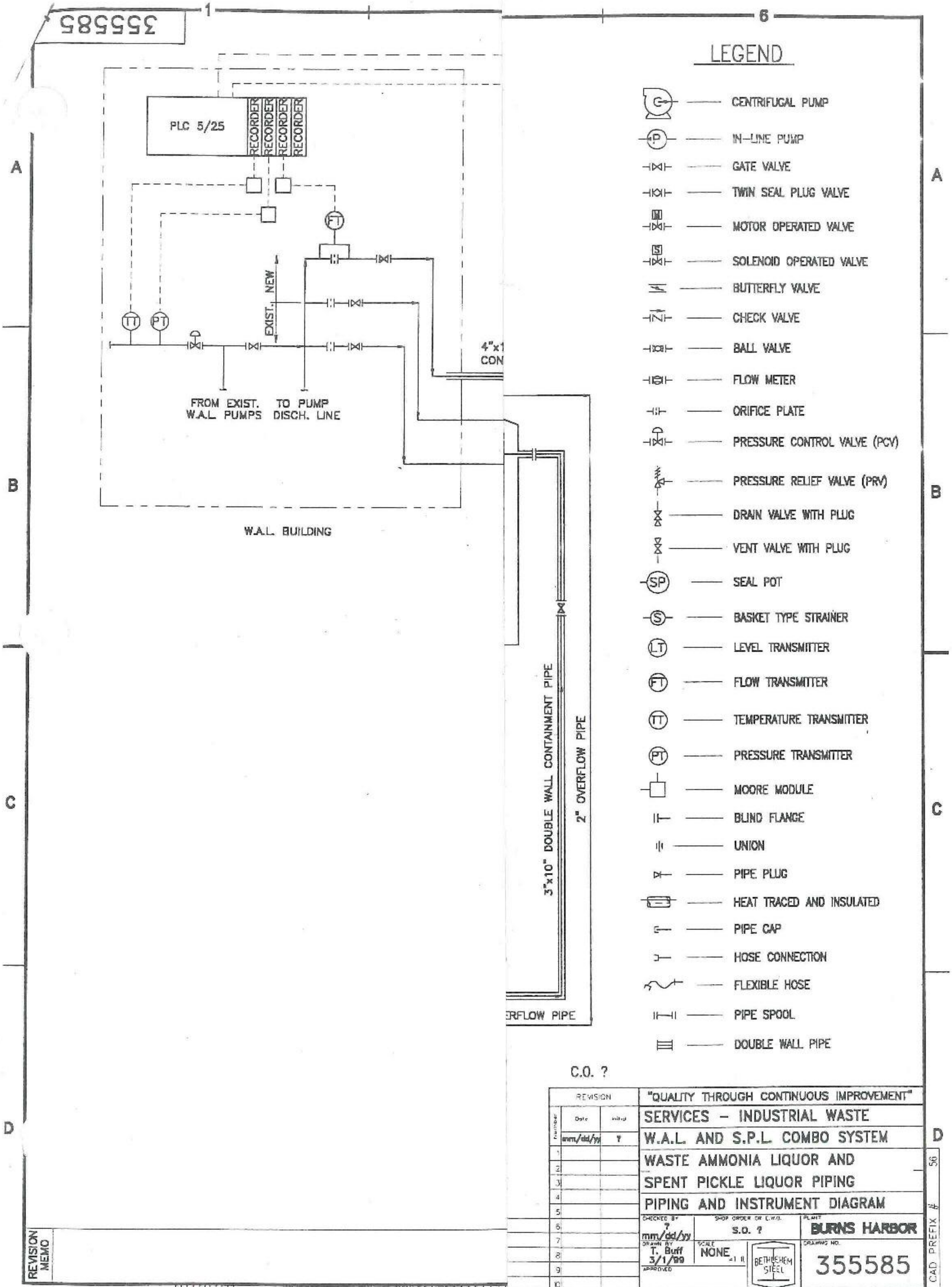
TEXAS WORLD OPERATIONS HOUSTON, TX		
BETHLEHEM STEEL COPR. WAL/SPL-1		
DR. BY RFW	02/26/99	REV:0

September 18, 2001
Ref: PF/UIC/DW

Bethlehem Steel Corporation
Burns Harbor Division

Additional Information for WAL/SPL Well Application
UIC Permit Number IN-127-1W-0007

Attachment 3 - WAL/SPL Well Management Conceptual Design



355585
PLC 5/25
RECORDER
RECORDER
RECORDER
RECORDER
FT
TT
PT
NEW
EXIST.
FROM EXIST. W.A.L. PUMPS
TO PUMP DISCH. LINE
W.A.L. BUILDING
3"x10" DOUBLE WALL CONTAINMENT PIPE
2" OVERFLOW PIPE
ERFLOW PIPE
LEGEND
CENTRIFUGAL PUMP
IN-LINE PUMP
GATE VALVE
TWIN SEAL PLUG VALVE
MOTOR OPERATED VALVE
SOLENOID OPERATED VALVE
BUTTERFLY VALVE
CHECK VALVE
BALL VALVE
FLOW METER
ORIFICE PLATE
PRESSURE CONTROL VALVE (PCV)
PRESSURE RELIEF VALVE (PRV)
DRAIN VALVE WITH PLUG
VENT VALVE WITH PLUG
SEAL POT
BASKET TYPE STRAINER
LEVEL TRANSMITTER
FLOW TRANSMITTER
TEMPERATURE TRANSMITTER
PRESSURE TRANSMITTER
MOORE MODULE
BLIND FLANGE
UNION
PIPE PLUG
HEAT TRACED AND INSULATED
PIPE CAP
HOSE CONNECTION
FLEXIBLE HOSE
PIPE SPOOL
DOUBLE WALL PIPE
C.O. ?
REVISION
Number
Date
Initial
mm/dd/yy
?
"QUALITY THROUGH CONTINUOUS IMPROVEMENT"
SERVICES – INDUSTRIAL WASTE
W.A.L. AND S.P.L. COMBO SYSTEM
WASTE AMMONIA LIQUOR AND
SPENT PICKLE LIQUOR PIPING
PIPING AND INSTRUMENT DIAGRAM
CHECKED BY
? mm/dd/yy
SHOP ORDER OR C.W.O.
S.O. ?
PLANT
BURNS HARBOR
DRAWN BY
T. Buff 3/1/99
SCALE
NONE
APPROVED
BETHLEHEM STEEL
DRAWING NO.
355585
CAD PREFIX #
56
REVISION MEMO
A
B
C
D
1
6
1/10"
1/8"—1/4"

September 18, 2001
Ref: PF/UIC/DW

Bethlehem Steel Corporation
Burns Harbor Division

Additional Information for WAL/SPL Well Application
UIC Permit Number IN-127-1W-0007

Attachment 4 - Waste Minimization Certifications

September 18, 2001
Ref: PF/UIC/DW

Waste Ammonia Liquor Waste Minimization Certification

Waste Ammonia Liquor (WAL) is generated as a by-product of the coking operation. Coal is the input to the coke operation and coke, coke oven gas and coal tar are the principal outputs. The WAL is recirculated in a closed-loop recycle system and is used to cool and cleanse the coke oven gas produced. The clean coke oven gas is used as a fuel throughout the plant.

Excess water is introduced into the closed-loop WAL system primarily as a result of the liberation of moisture, which is contained within the coal, during the coking process. The excess WAL is removed from the closed-loop system and disposed via the deepwells.

Bethlehem has also actively pursued eliminating any additional sources of water that could potentially enter this closed-loop system. These types of activities have included:

- Replacing the steam aspiration system at the No. 2 Coke Oven Battery with high-pressure WAL aspiration.
- Using WAL to cool the seals on the WAL recycle pumps rather than lake water.

These activities have significantly reduced the volume of WAL injected by reducing the potential sources of fresh water addition to the closed-loop recycle system. For example, the average daily amount of WAL injected into the deepwells in 1996 was about 244,000 gallons. In 2000, the daily amount injected averaged about 191,000 gallons. Bethlehem will continue to watch the amounts of WAL disposed and evaluate if further waste reduction methods can be implemented.

September 18, 2001
Ref: PF/UIC/DW

Spent Pickle Liquor Waste Minimization Certification

Spent Pickle Liquor (SPL) is generated as a by-product of the steel sheet pickling operation. The continuous pickling operation uses a hydrochloric acid solution, in a cascading (e.g., counter-current flow) system, to remove scale and rust from the steel strip prior to further finishing.

SPL is a listed hazardous waste (40 CFR 261, Code K062) when disposed. The SPL contains a high percentage of iron, some trace metals consistent with the composition of the steel being pickled, chloride salts and some free hydrochloric acid. The SPL has a relatively high specific gravity (typically 1.20 to 1.30).

The Burns Harbor division generates a very clean SPL with very low concentrations of trace metals. This makes the material ideally suited as a substitute for commercial products that are used at municipal wastewater treatment plants for sludge conditioning and phosphorous removal.

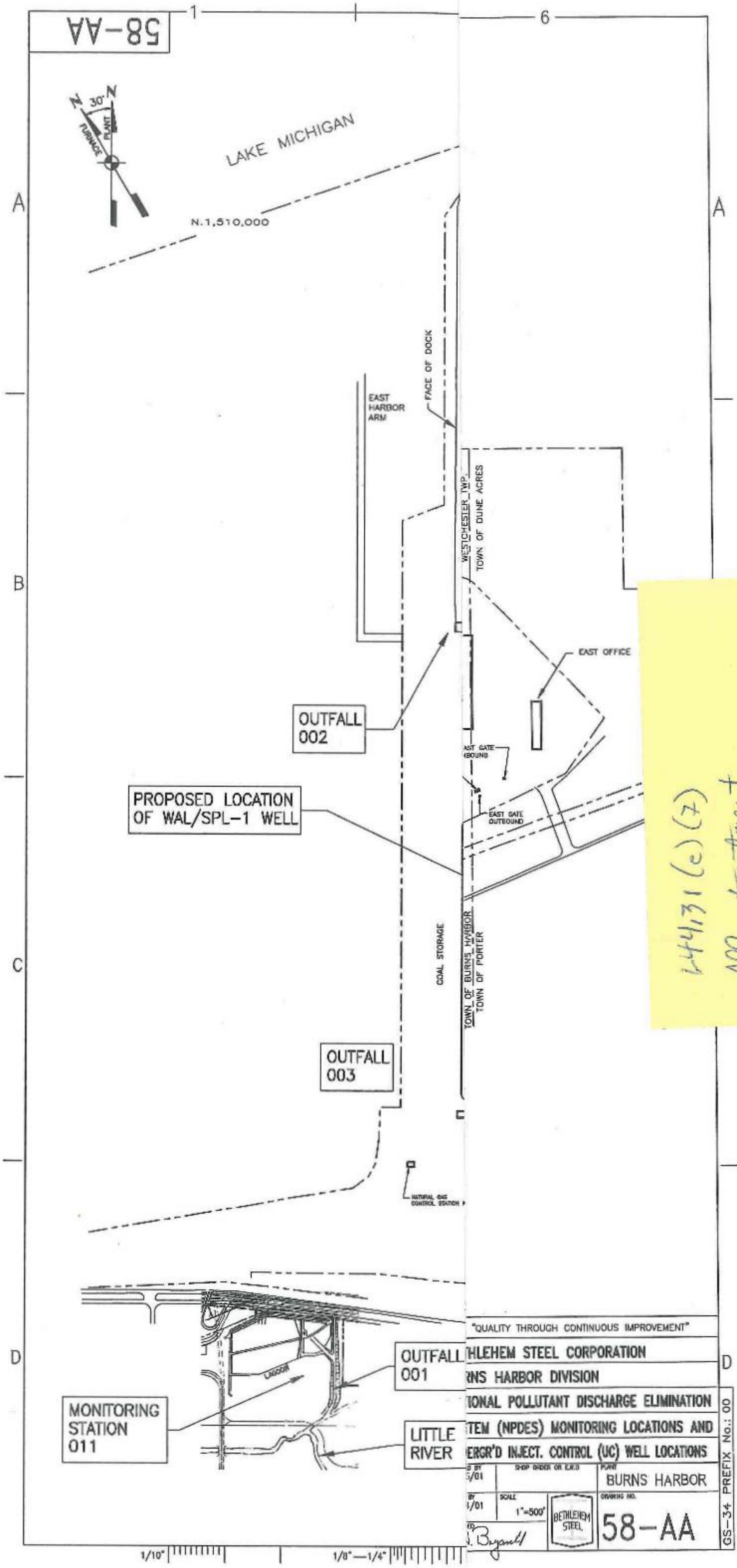
Bethlehem Steel continues to actively pursue the sale of this by-product to municipal wastewater treatment plants. Only that portion of the SPL that cannot be marketed as a by-product is injected into the deepwell.

September 18, 2001
Ref: PF/UIC/DW

Bethlehem Steel Corporation
Burns Harbor Division

Additional Information for WAL/SPL Well Application
UIC Permit Number IN-127-1W-0007

Attachment 5 - Facility Map



144.31(e)(7)
All treatment
storage
disposal

w.a.l. 1 not above
Two Outfall 003

RECEIVED
MAY 14 2007
UIC BRANCH
EPA REGION 5

ISG Burns Harbor, LLC.
Construction Details for UIC Permit No. IN-127-1W-0007

Attachment 2 - Construction Procedures and Construction Details (Clean Version)

After the conductor is in place, a suitable drilling rig will be moved to location and rigged up. A flow line connecting the steel solids control and drilling fluid tanks into the side of the conductor will be welded in place. The rig will utilize a closed loop mud system during drilling. All generated cuttings above the injection interval will be collected in steel pits and dewatered for disposal on site. Fluids will be collected and properly disposed using either the existing wells or an off-site disposal service.

Following rig up, a 26" hole will be drilled from the surface to ±245 feet through the glacial deposits and approximately 45 feet into the top of the Silurian-Devonian formation. A 20" threaded and coupled conductor will be run in the hole and cemented using conventional cement circulation techniques. A cement volume of no less than 50% excess of the calculated hole volume will be pumped initially. If the cement top falls back after cementing, the annulus will be filled with additional cement by the tremie method. The casing will remain hung from the rig for a minimum of 12 hours to allow the cement to cure without disturbance.

SURFACE CONDUCTOR.

Surface to ±245 feet
20", J-55 or K-55, 94 lbs/ft, 8rd, ST &C (or equivalent)

Internal Diameter:	19.124 inches
Drift Diameter:	18.936 inches
O.D. of Coupling:	21.000 inches
Collapse:	520 psi
Body Yield:	1,480,000 pounds
Internal Yield:	2,110 psi
Joint Strength:	784,000 pounds

SURFACE CONDUCTOR CEMENTING EQUIPMENT

Item #	Qty	Description
1.	1	20" guide shoe with float
2	1 jt.	20", 94 lbs/ft, J or K-55, 8rd, ST&C
	2	Steel spring centralizer, 1- 10' above shoe, 1-10' below collar
3.	1	Float collar sub
4.	5 jts.	20", 94 lbs/ft, J or K-55, 8rd, ST &C
	2	Steel spring centralizer, 1- between joints 3&4, 1- between joints 1&2

Note relative to all cementing:
All capacities, volumes, pipe weights, diameters, etc. were obtained from Halliburton Cementing Tables per standard API practice.

SURFACE CONDUCTOR CEMENT:

Casing: 20", J-55 or K-55, 94 lbs/ft, ST&C
Cement: Class A with 2% Calcium Chloride

	Size	Volume Constant
Hole Diameter:	26"	3 .69 cu ft/ln ft
Capacity of open hole annulus:	20" vs 26"	1.51 cu ft/ln ft
Capacity of cased hole annulus:	20" vs 30"	2.48 cu ft/ln ft

13-3/8 inch, 54.50 pound/foot, J-55 or K-55 casing. The casing will include a float shoe, a float collar, an external casing packer (optional), a cementing stage tool (optional), and sufficient spring steel centralizers to center the casing in the hole. The two stage cementing procedure and the external casing packer are included in the procedure to address potential lost circulation in the Trenton formation. If the lost circulation zone is not encountered, ISG may elect to perform a single stage cement job and not install the external casing packer and cementing stage tool in the casing string. The casing will be circulated to clear debris from the casing and hole. The first stage of the cement job is planned to utilize a minimum cement volume equal to no less than 120% of the measured hole volume from total depth to approximately 900 feet. Class A cement with 2% calcium chloride is planned for this stage. After the cement is circulated into place, the external casing packer will be inflated. This procedure will isolate additional cement column pressure from being exerted on the Trenton formation. After inflating the external casing packer, the cementing stage collar will be opened and any excess first stage cement will be circulated from the annulus. The second stage cementing will be performed after the first stage cement is allowed to cure approximately 6 hours to obtain initial compressive strength. A combination of light weight lead cement and dense tail cement will be used to cement the second stage. Following the cementing procedure, the casing will be hung from the drilling rig for a minimum of 12 hours.

SURFACE CASING:

Surface to ±1200 feet

13-3/8", J-55 or K-55, 54.50 lbs/ft, 8rd, ST &C (or equivalent)

Internal Diameter	12.615 inches
Drift Diameter:	12.459 inches
O.D. of Coupling:	14.375 inches
Collapse:	1,130 psi
Body Yield:	853,000 pounds
Internal Yield:	2,730 psi
Joint Strength:	547,000 pounds

SURFACE CASING CEMENTING EQUIPMENT:

Item#	Qty	Description
1.	1	13-3/8" guide shoe with float
2.	2 jts	13-3/8", 54.50 lbs/ft, J or K-55, 8rd, ST&C
	3	Steel spring centralizers, 1- 10' above shoe, 1-10' below collar, 1-middle of second joint
3.	1	13-3/8" float collar sub
4.	3 jts	13-3/8", 54.50 lbs/ft, J or K 55, 8rd, ST &C
	2	Steel spring centralizer, 1 - between joints 2&3, 1- between joints 4&5
	2	Canvas cement baskets on the 10' and 20' from the top of joint 6
5.	2 jts	13-3/8", 54.50 lbs/ft, J or K-55, 8rd, ST &C
6.	1	13-3/8" External Casing Packer
7.	1	13-3/8" Cementing Stage Collar
8.	23 jts	13-3/8", 54.50 lbs/ft, J or K 55, 8rd, ST&C
	7	Steel spring centralizers, 1 every third joint starting with the top of joint 9

Yield Per Sack:	2.06 cu ft/sk
No. of Sacks:	329 sacks

Surface Casing Cement

Second Stage Tail cement

Cement: Class A with 2% Calcium Chloride

Hole Diameter:	17-1/2"	1.67 cu ft/ln ft
Capacity of open hole annulus:	13-3/8" vs 17-1/2"	0.69 cu ft/ln ft
Capacity of cased hole annulus:	13-3/8" vs 20"	1.02 cu ft/ln ft
Capacity of 13-3/8" Casing:		0.87 cu ft/ln ft

	Top (ft)	**Bottom (ft)**	**Total (ft)**
Cased open hole:	700	900	200 feet

Annular Volume 13-3/8" in 17-1/2":	138.92 cu ft
Total:	138.92 cu ft
20% excess:	27.78 cu ft
Total volume:	166.70 cu ft

Yield Per Sack:	1.18 cu ft/sk
No. of Sacks:	142 sacks

After waiting 12 hours, the flow line and BOP's will be removed. A casing spool, hanger, and seals will be installed. The BOP's and flow line will be re-installed. The Single Pass Temperature Log will be run 12 to 36 hours after the completion of the cementing operations if cement returns are not observed at the surface. After allowing a minimum of 48 hours cure time, a cement bond log with variable density and a single pass temperature log (if cement returns are observed) will be run.

Cased Hole Logging Program

Single Pass Temperature
Cement Bond with Variable Density

If the bond log records sufficient cement bond, work will continue. If insufficient cement bonding is shown, a remedial cementing plan will be initiated before drilling out. The casing will be pressure tested to 1000 psi for one hour. If the test pressure changes less than 3 %, the casing pressure test will be considered acceptable. If the pressure test does not meet the requirements, the surface pressure control equipment will be investigated to insure the source of the pressure loss is not on the surface. The test will be repeated until the pressure loss is confirmed and quantified. If the casing will not test, a test packer will be used to locate and quantify the leak. After locating and quantifying the leak, a detailed plan will be designed to restore the mechanical integrity of the casing.

A 12-1/4 inch diameter drill bit will be used to drill out the float shoe, cement remaining in the casing, and the guide shoe. A 12-1/4 inch hole will be drilled from 1,200 feet to the top of the Precambrian Formation using water, gel sweeps, and possibly air assisted drilling techniques to keep the hole clean of cuttings. The Precambrian is expected to be encountered between 4,300 feet and 4,400 feet.

the compressional and shear wave travel times of the geologic formations. In combination with the bulk density tool measurements, the dynamic elastic constants (Young's Modulus, Poisson's Ratio, Shear Modulus) can be calculated from the sonic tool data. From the dynamic elastic constants, the far-field stresses (tensile strength, overburden pressure, and fracture pressure) can be calculated and presented as a "mechanical properties log" type display. The mechanical properties presentation can be calibrated to core data and the results of the Mt. Simon open-hole injection interval fracture gradient tests.

A mechanical properties log (Baker Atlas X Mac Tool, Schlumberger's Full Wave Form Sonic Tool or other equivalent tool) will be run over the injection and confining intervals of the well. The log will be processed to determine the rock properties discussed above.

The open hole injection interval will be isolated by installing a wireline set umbrella plug at a depth of approximately 2,790 feet and then spotting sand and cement above the plug. Approximately 10 feet of sand fill will be spotted immediately above the plug in the wellbore. Then a balanced cement plug will be spotted from 2,780 feet (top of sand) to approximately 2,740 feet. The cement will be allowed to cure for a minimum of 8 hours. The cement top will be located and drilled down to the desired casing setting depth of approximately 2,755 feet with a 12-1/4 inch bit on the drilling assembly.

Casing crews will be used to properly tighten the 9-5/8 inch protection casing while it is being run into the wellbore. The protection casing will be run to a depth of approximately 2,755 feet. The actual depth will be determined from the logs. The first section of casing will consist of a 9-5/8 inch carbon steel float shoe, two joints of 9-5/8 inch casing, and a 9-5/8 inch carbon steel float collar. Then approximately 16 joints of 9-5/8 inch casing will be run and a 9-5/8 inch cementing stage tool will be installed in the string at approximately 2,050 feet. The remainder of the 9-5/8 inch casing will be installed in the well. The well will be circulated clean. The lower section of the casing from 2,755 feet to 2,050 feet will be cemented with Class "A" cement. The upper section of casing from 2,050 feet to surface will be cemented with a combination of Class A cement and Class A Lite cement.

PROTECTION CASING:

Surface to 2,755 feet

9-5/8", N-80, 40 lbs/ft, 8rd, LT&C (or equivalent)

Internal Diameter:	8.835 inches
Drift Diameter:	8.679 inches
O.D. of Coupling:	10.625 inches
Collapse:	3,090 psi
Body Yield:	916,000 pounds
Internal Yield:	5,750 psi
Joint Strength:	737,000 pounds

PROTECTION CASING CEMENTING EQUIPMENT

Item #	Qty	Description
1.	1	9-5/8", 40 lbs/ft, N-80, 8rd, LT&C float shoe
2.	2 jts	9-5/8", 40 lbs/ft, N-80, 8rd, LT&C
3.	1	9-5/8", 40 lbs/ft, N-80, 8rd, LT&C float collar
	4	9-5/8""" Steel spring centralizer, 2 on each of the first two joints.
4.	16 jts	9-5/8", 40 lbs/ft, N-80, 8rd, LT&C
	8	9-5/8" Steel spring centralizer, 1 on every other joint.

Yield Per Sack:	2.06 cu ft/sk
No. of Sacks:	370 sacks

Protection Casing Cement

Second Stage Tail Cement

Cement: Class A with 2% Calcium Chloride

Hole Diameter:	12-1/4"	0.82 cu ft/ln ft
Capacity of open hole annulus:	9-5/8" vs 12-1/4"	0.31 cu ft/ln ft

	Top (ft)	Bottom (ft)	Total (ft)
Cased open hole 9-5/8":	1850	2050	200

Annular Volume 9-5/8" in 12-1/4":	62.00 cu ft
20% excess:	12.40 cu ft
Total volume:	74.40 cu ft

Yield Per Sack:	1.18 cu ft/sk
No. of Sacks:	63 sacks

The casing will be cut, the BOP's removed, a 9-5/8 inch hanger, seal, and a tubing spool installed. The Single Pass Temperature Log will be conducted 12 to 36 hours after completion of the cementing operations if cement returns are not observed at the surface. The cement will be allowed to cure for a minimum of 48 hours An 8-5/8 inch bit will be installed on the drill string and lowered in the well to the cementing stage tool at a depth of approximately 2,050 feet. The cementing plugs and baffle in the stage tool will be removed by drilling. The bit and drilling assembly will be lowered in the well to the depth of the 9-5/8 inch float collar at approximately 2,670 feet. The first stage cementing plugs and float collar will be drilled up. The cement inside the two joints of 9-5/8 inch casing between the float collar and float shoe will be removed by drilling to a depth of approximately 2,745 feet. Approximately 10 feet of cement will be left in the casing for the casing pressure test. A logging truck will be rigged up to run the following logs:

CASED HOLE LOGGING PROGRAM

Single Pass Temperature Log
Cement Bond with Variable Density
Electro-Magnetic Casing Inspection

After logging, the 9-5/8 casing will be pressure tested to 1500 psi for one hour. If the test pressure does not change more than 3% during the hour, the test will be considered acceptable. After pressure testing, the drilling assembly with an 8-5/8 inch bit will be lowered into the well to the top of the cement in the 9-5/8 inch casing. The remaining cement in the casing and the 9-5/8 inch float shoe will be removed by drilling. The drilling assembly will be lowered in the well to check for fill or solids in the wellbore. Fill or solids will be circulated out of the well to the total depth of the well, approximately 4,300 feet. The drilling assembly will be removed from the well.

A 9-5/8 inch test packer will be installed on the drill pipe and lowered in the well to approximately 2,735 feet. The test packer will be set in the 9-5/8 inch casing at this depth. Either coiled tubing or a

May 2007

ISG BURNS HARBOR, LLC.
WAL-3
CEMENTING EQUIPMENT

Surface Conductor

Item #	Qty.	Description
1.	1	20 inches, guide shoe with float
2.	1 jt	20 inches, 94 lbs/ft, J-55 or K-55, 8rd, ST&C
	2	Steel spring centralizer, 1-10 feet above shoe, 1-10 feet below collar
3.	1	Float collar sub
4.	5 jts	20 inches, 94 lbs/ft, J or K-55, 8rd, ST&C
	2	Steel spring centralizer 1- between joints 3&4, 1- between joints 1&2

Surface Casing

Item #	Qty	Description
1.	1	13-3/8 inches guide shoe with float
2.	2 jts	13-3/8 inches, 54.50 Ibs/ft, J-55 or K-55, 8rd, ST&C
	3.	Steel spring centralizers, 1 - 10 feet above shoe, 1 - 10 feet below collar , 1-middle of second joint
3.	1	13-3/8 inches float collar sub
4.	3 jts	13-3/8 inches, 54.50 lbs/ft, J-55 or K-55, 8rd, ST&C
	2	Steel spring centralizer, 1 - between joints 2&3, 1- between joints 4&5
	2	Canvas cement baskets 10 feet and 20 feet from the top of joint 6
5.	2 jts	13-3/8 inches, 54.50 lbs/ft, J-55 or K-55, 8rd, ST&C
6.	1	13-3/8 inches, External Casing Packer
7.	1	13-3/8 inches, Cementing Stage Collar
8.	23 jts	13-3/8 inches, 54.50 lbs/ft, J-55 or K-55, 8rd, ST&C
	7	Steel spring centralizers, 1 every third joint starting with the top of joint 9

May 2007

ISG BURNS HARBOR, LLC.
WAL-3
CASING PROGRAM AND SPECIFICATIONS

CONDUCTOR:	Surface to ±40' or point of refusal 30", .375" or .500" wall, carbon steel (or equivalent)	
SURFACE CONDUCTOR:	Surface to ±245 feet 20", J-55 or K-55, 94 lbs/ft, 8rd, ST&C (or equivalent)	
	Internal Diameter:	19.124 inches
	Drift Diameter:	18.936 inches
	O.D. of Coupling:	21.000 Inches
	Collapse:	520 psi
	Body Yield:	1,480,000 pounds
	Internal Yield:	2,110 psi
	Joint Strength:	784,000 pounds
SURFACE CASING:	Surface to ±1200 feet 13-3/8", J-55 or K-55, 54.50 lbs/ft, 8rd, ST&C (or equivalent)	
	Internal Diameter:	12.615 inches
	Drift Diameter:	12.459 inches
	O.D. of Coupling:	14.375 inches
	Collapse:	1,130 psi
	Body Yield:	853,000 pounds
	Internal Yield:	2,730 psi
	Joint Strength:	547,000 pounds
PROTECTION CASING:	Surface to ±2,755 feet 9-5/8", N-80, 40 lbs/ft, 8rd, LT&C (or equivalent)	
	Internal Diameter:	8.835 inches
	Drift Diameter:	8.679 inches
	O.D. of Coupling:	10.625 inches
	Collapse:	3,090 psi
	Body Yield:	916,000 pounds
	Internal Yield:	5,750 psi
	Joint Strength:	737,000 pounds

ISG BURNS HARBOR, LLC.
WAL-3
DRILLING PROGRAM

STEP TASK

1. Prepare the location by removing as much miscellaneous equipment from the area as possible.

2. Survey the location and stake the well site.

3. Drive a 30 inch diameter, 0.375 inch or .500 inch wall carbon steel conductor to ±40 feet or refusal.

4. Move in and rig up the drilling rig with all the necessary ancillary equipment. The rig should include a substructure with rotary table, two sets of pipe racks, catwalk and V-door, two steel tanks, two mud pumps, dog house, adequate generators for the mud system and the rig, drilling instrumentation and slick line.

5. Set up a closed loop mud system which includes necessary solids control equipment. All drill cuttings from steps 6 through 29 will be placed in roll off boxes or staged in a contained area for disposal on-site.

6. Drill the rat hole and mouse hole.

7. Drill a 26 inch hole to approximately 245 feet using water and native mud. A single shot deviation survey will be made every third joint drilled (approximately 100 feet).

8. Circulate and condition the hole for casing.

9. Install approximately 245 feet of 20 inch, 94 pounds/foot, J or K-55, 8 rd, ST&C casing or comparable with a float shoe and float collar. See the attached Casing Program and Specifications for the details on the tubulars. The details on the float equipment and centralizers are included in the attached Cementing Equipment section for the Surface Conductor.

10. Prepare to cement the casing string.

11. Circulate the hole clean

12. Cement the casing with Class A cement with 2% calcium chloride. The calculated volume plus approximately 50% excess will be emplaced. After

compressive strength. See the attached Cement Calculations section for more details.

23. Perform second stage of cement job with lead slurry of Class "A" Lite cement plus 20% excess and a tail slurry of Class "A" cement with 2% calcium chloride plus 20% excess. Land the cement displacement plug and confirm that the cementing stage tool shifted to the closed position. Allow the cement to cure for a minimum of 12 hours while hanging from the slips.

24. Cut off the casing to the proper height and mount a casing spool, hanger and seals.

25. Nipple up the BOP. Function test the BOP. Pressure test the BOP and lines to 2,000 psi using a test plug. If BOP's will not pressure test, locate source of leak and repair or replace BOP's.

26. Perform a single pass temperature log 12 to 36 hours after completion of the cementing operations if cement returns are not observed at surface. If returns are observed, the temperature survey will be performed with the cement bond log (See step 28).

27. Wait on cement for a minimum of 48 hours prior to performing the cased hole cement bond logging operations.

28. Rig up the electric logging company and run the following electric logs from casing plug back TD to surface.
    a.) Single Pass Temperature (if not run under step 26, above)
    b.) Cement Bond with Variable Density

29. Pressure test the casing to 1000 psi for one hour. The test will be considered successful if there is less than a 3% gain or loss in pressure after one hour. If the pressure test is not acceptable, the surface pressure control equipment will be investigated to make sure the source of the pressure loss is not on the surface. The test will be repeated until the pressure loss is confirmed and quantified. If the casing will not pass the required pressure test, a test packer will be located and ordered. A series of pressure tests will be performed on the casing using the test packer to locate and quantify the source of the casing leak. After identifying the location of the leak, a detailed plan will be designed and performed to restore the mechanical integrity of the casing string. After the remedial procedure is complete, the casing will be pressure tested again at 1000 psi for one hour.

30. Pick up a 12-1/4 inch bit, 13-3/8 inch casing scraper, and bottomhole assembly and lower in the well on the drill pipe. Drill out the surface casing. Do not exceed

approximately 3300 feet to 3700 feet. Perform open hole fracture gradient testing.

43. Remove test equipment, pick up 12-1/4 inch drilling assembly and drill a 12-1/4 inch hole from approximately 3700 feet to 4200 feet.

44. Circulate and condition hole for anchor fracture gradient determination test. Remove drill string and run in hole with anchor test assembly. Isolate zone from approximately 3800 feet to 4200 feet. Perform open hole fracture gradient testing.

45. Remove test equipment, pick up 12-1/4 inch drilling assembly and drill a 12-1/4 inch hole from approximately 4200 feet to 4400 feet.

46. Circulate and condition the hole for logs. Rig up the electric loggers. Run the following electric logs from 4400 feet to 1200 feet.
    a.) Dual Induction _ Spontaneous Potential – Gamma Ray
    b.) Formation Density – Compensated Neutron – Gamma Ray
    c.) Open Hole Caliper – Gamma Ray
    d.) Gyroscopic survey from surface to total depth
    e.) Fracture Finder Log (Baker Atlas' Star Tool or Equivalent)
    f.) Mechanical Properties Log (Baker Atlas' X Mac Tool or Equivalent)

47. Run a shear sonic tool through the injection zone and confining zone in order to determine the compressional and shear wave travel times of the geologic formations.

48. If adequate core recovery was not obtained in steps 34 and 40, obtain sidewall core samples from the confining zone and injection interval.

49. Run in the hole with the drill string to circulate and condition the hole for casing. Pull out of the hole laying down the drill string.

50. The open hole injection interval will be isolated by installing a wireline set umbrella plug at a depth of approximately 2,790 feet and then spotting sand and cement above the plug. Approximately 10 feet of sand fill will be spotted in the wellbore immediately above the plug. Then a balanced cement plug will be spotted from 2,780 feet (top of sand) to approximately 2,740 feet.

51. Allow the cement plug to cure for a minimum of 8 hours.

52. Pick up a 12-1/4 inch bit and lower in the well on the drilling assembly to the top of the cement plug at approximately 2,740 feet. Remove the cement by drilling to the desired casing setting depth of approximately 2,755 feet.

61. Rig up the electric logging company and run the following electric logs from casing plug back TD to surface:
    a.) Temperature Log (if not run under step 59, above)
    b.) Cement Bond Log with Variable Density
    c.) Electro Magnetic Casing Inspection Log

62. Pressure test the casing to 1000 psi for one hour. If the pressure changes less than 3% in the one-hour period the test will be considered successful. If the pressure test is not acceptable, the surface pressure control equipment will be investigated to make sure the source of the pressure loss is not on the surface. The test will be repeated until the pressure loss is confirmed and quantified. If the casing will not pass the required pressure test, a test packer will be located and ordered. A series of pressure tests will be performed on the casing using the test packer to locate and quantify the source of the casing leak. After identifying the location of the leak, a detailed plan will be designed and performed to restore the mechanical integrity of the casing string. After the remedial procedure is complete, the casing will again be tested at 1000 psi for one hour.

63. Pick up a 8-5/8 inch bit and three drill collars and lower in the well on the drill pipe to the top of cement in the casing at approximately 2,740 feet. Drill through the remaining cement in the casing, cementing plugs, and float shoe with the 8-5/8 inch bit. Continue in the well with the 8-5/8 inch bit to the total depth of the well. Circulate any solids out of the well and displace drilling fluid out of the well with clear brine water. Remove the drilling assembly from the well.

64. Pick up a retrievable test packer for the 9-5/8 inch casing and lower in the well on the drill pipe. Set the packer at a depth of approximately 2,740 feet. Pressure test the packer and casing to a minimum pressure of 1,000 psi for one hour. The test will be successful if the pressure change is less than 3% per hour.

65. A fluid sample will be collected from the Mt. Simon open hole injection interval with jetting techniques using coiled tubing or a small diameter inner string and nitrogen. The pH, conductivity and temperature of the fluid recovered from the well will be monitored to determine when the fluid from the formation has stabilized. After the fluid stabilizes, the fluid sample will be collected. After the fluid sample is collected, the well will be allowed to recover and the fluid level will be measured to determine the static fluid level and bottom hole pressure of the injection interval.

66. Stimulate the well through the drill pipe as described in the stimulation plan.

ISG Burns Harbor, LLC.
WAL-3 Cement Calculations:

All capacities, volumes, pipe weights, diameters, etc. were obtained from Halliburton Cementing Tables per standard API practice.

Surface Conductor Cement:
Casing: 20", J-55 or K-55, 94 lbs/ft, ST&C
Cement: Class A with 2% Calcium Chloride

	Size	Volume Constant
Hole Diameter	26"	3.69 cu ft/ ln ft
Capacity of open hole annulus	20" vs. 26"	1.51 cu ft/ in ft
Capacity of cased hole annulus	20" vs. 30"	2.48 cu ft/ in ft
Capacity of 20" Casing		1.99 cu ft/ in ft

	Top (ft)	Bottom (ft)	Total
Cased hole depth	0	40	40 feet
Cased open hole	40	240	200 feet
Open hole	240	245	5 feet

Annular Volume	20" vs. 30"	99.39 cu ft
Annular Volume	20" vs. 26"	301.06 cu ft
Hole Volume	26"	18.44 cu ft
Volume Left in 20" casing (40 feet)		79.79 cu ft
Total		498.67 cu ft
50% excess		249.34 cu ft
Total volume		748.01 cu ft

Yield Per Sack: 1.18 cu ft/sk
No. of Sacks: 634 sacks

Surface Casing Cement:

First Stage Cement

Casing: 13-3/8", J or K-55, 54.50 lbs/ft, ST&C
Cement: Class A with 2% Calcium Chloride

Hole Diameter	17 1/2"	1.67 cu ft/ in ft
Capacity of open hole annulus	13-3/8" vs. 17-1/2"	0.69 cu ft/ in ft
Capacity of cased hole annulus	13-3/8" vs. 20"	1.01 cu ft/ in ft
Capacity of 13-3/8" Casing		0.87 cu ft/ in ft

Capacity of open hole annulus	13-3/8" vs. 17-1/2"	0.69 cu ft/in ft
Capacity of cased hole annulus	13-3/8" vs. 20"	1.02 cu ft/ in ft
Capacity of 13-3/8" Casing		0.87 cu ft/ in ft

	Top (ft)	Bottom (ft)	Total (ft)
Cased open hole	700	900	200 feet

Annular Volume 13-3/8" in 17-1/2"	138.92 cu ft
Total	138.92 cu ft
20% excess	27.78 cu ft
Total volume	166.70 cu ft

Yield Per Sack : 1.18 cu ft/sk
No of Sacks: 142 sacks

Protection Casing Cement [Note: The following program is designed to ensure that a minimum quantity of 120% of the amount of cement necessary to fill the calculated volume of the annular space is used. The first stage cement slurry is limited to 10% excess. The second stage cement slurries include 20% excess for the lead cement and the second stage tail cement calculation is based on 20% excess]

First Stage Cement

Cement: Class A with 2% Calcium Chloride

Hole Diameter	12-1/4"	0.82 cu ft/in ft
Capacity of open hole annulus	9-5/8" vs. 12-1/4"	0.31 cu ft/in ft
Capacity of 9-5/8" Casing		0.43 cu ft/In ft

	Top (ft)	Bottom (ft)	Total (ft)
Cased hole depth	0	0	0 feet
Cased open hole 9-5/8"	2050	2755	705 feet

Annular Volume 9-5/8" in 12-1/4"	218.55 cu ft
Volume of 80 ft of 9-5/8" Casing	34.40 cu ft
Total	252.95 cu ft
10% excess	25.30 cu ft
Total volume	278.25 cu ft

Yield per Sack: 1.18 cu ft/sk
No. of Sacks: 236 sacks

Protection Casing Cement

Second Stage Lead Cement

Cement: Class A Lite

September 18, 2001
Ref: PF/UIC/DW

Bethlehem Steel Corporation
Burns Harbor Division

Additional Information for WAL/SPL Well Application
UIC Permit Number IN-127-1W-0007

Attachment 1 - Revised Drilling Program in Dialog Format
(Revised Pages 3-13 to 3-26 of March 24, 1999 Permit Application)

out of date -
new version
dated 2007

ATTACHMENT L & M-CONSTRUCTION PROCEDURES and CONSTRUCTION DETAILS

WAL/SPL-1 will be constructed utilizing procedures and materials that insure that the well is suitable for injection of either WAL or SPL. Proposed construction procedures and materials are discussed in this attachment. A schematic diagram of the proposed construction details of WAL/SPL-1 is included as Figure 3-4. This figure also compares the proposed well configuration to a stratigraphic column of the sub-surface geology expected at the proposed location. A wellhead schematic is included as Figure 3-5.

This attachment consists of six (6) major parts.

Drilling Program in Dialog Format (in the following text)
Drilling Program by Task (in Appendix A)
Electric Logging Program (in Appendix A)
Casing Program and Specifications (in Appendix A)
Cementing Equipment Data (in Appendix A)
Cement Program (in Appendix A)

DRILLING PROGRAM IN DIALOG FORMAT

All depths referenced in this drilling program are based upon the drilling rig's rotary kelly bushing being eighteen feet above ground level. All depths have been approximated using historical drilling data from the other wells and regional information. Actual formation and completion depths will be based on in-situ logging conducted during the drilling and steel line measurements made during installation. All of the cementing volumes used to calculate material requirements are based on gauge hole. Actual cement volumes and final cement additive selection will be based on log information and drilling conditions. A completion report containing all of the required and pertinent information will be prepared and submitted after construction is completed. The actual depths and volumes used will be included in the report.

It is BSC's practice to keep the USEPA UIC technical personnel fully apprised of drilling activities by means of a faxed daily report and telephone conversations. This program will be incorporated into the reporting of all activities during drilling and completion based upon mutual agreement of subject and content between BSC and the UIC group. This drilling program sets forth the minimum construction standards and procedures that will be used during construction. Major or minor changes required by actual drilling conditions will be discussed with the proper regulatory personnel as they arise.

After the site is cleared and graded, a 30" conductor will be driven to 40 feet or refusal by pile driving, or drilled and cemented using a conductor setting service.

CONDUCTOR: Surface to 40' or point of refusal
30", .375" or .500" wall, carbon steel

During the drilling of the Galesville monitoring well, severe washout beneath the drilling rig sub-structure occurred. To reduce the chance of reoccurrence, a driven conductor has been added.

After the conductor is in place, a suitable drilling rig will be moved to location and rigged up. A flow line connecting the steel recirculating tanks into the side of the conductor will be welded in place. The rig will utilize a closed loop mud system during drilling. All generated cuttings will be collected in steel pits for disposal on site. Fluids will be collected and properly disposed using BSC's appropriate liquid and sludge facilities.

Following rig up, a 26" hole will be drilled from the surface to 245 feet through the glacial deposits and approximately 45 feet into the top of the Silurian-Devonian formation. A 20" threaded and coupled conductor will be run in the hole and cemented using conventional cement circulation techniques. A cement volume of no less than 100% excess of the calculated hole volume will be pumped initially. If the cement top falls back after cementing, the annulus will be filled with additional cement by the tremie method. The casing will remain hung from the rig for a minimum of 24 hours to allow the cement to cure without disturbance.

SURFACE CONDUCTOR:

Surface to 240 feet
20", J-55, 94 lbs/ft, 8rd, ST&C

Drift Diameter:	18.936 inches
O.D. of Coupling:	21.000 inches
Collapse:	520 psi
Body Yield	1,480,000 pounds
Internal Yield	2,110 psi
Joint Strength:	784,000 pounds

SURFACE CONDUCTOR
CEMENTING EQUIPMENT

Item #	Qty	Description
1.	1	20" guide shoe with float
2.	1 jt	20" , 94 lbs/ft, J or K 55, 8rd, ST&C
	2	Steel spring centralizer, 1- 10' above shoe, 1-10'feet below collar
3.	1	Stab-in float sub
4.	5 jts	20", 94 lbs/ft, J or K-55, 8rd, ST&C
	2	Steel spring centralizer 1- between joints 3&4, 1- between joints 1&2

Note relative to all cementing:

All capacities, volumes, pipe weights, diameters, etc. were obtained from Halliburton Cementing Tables per standard API practice.

Surface Conductor Cement:

Casing: 20", J-55, 94 lbs/ft, ST&C

Cement: Class A with 2% Calcium Chloride

	Size	Volume Constant	
Hole Diameter	26"	3.69 cu ft/ln ft	3.6870
Capacity of open hole annulus	20" vs 26"	1.51 cu ft/ln ft	1.5053
Capacity of cased hole annulus	20" vs 30"	2.48 cu ft/ln ft	
Capacity of 20" Casing		1.99 cu ft/ln ft	1.5947

	Top (ft)	Bottom (ft)	Total
Cased hole depth	0	40	40 feet
Cased open hole	40	240	200 feet
Open hole	240	245	5 feet

Annular Volume	20" vs 30"	99.39 cu ft	40 ft* 2.4847 cu ft/ln ft
Annular Volume	20" vs 26" ,	301.06 cu ft	200ft* 1.5053 cu ft/ln ft
Hole Volume	26"	18.44 cu ft	5 ft * 3.6870 cu ft/ln ft
Volume Left in 20" casing (40 feet)		79.79 cu ft	40 ft* 1.999.7 cu ft/ln ft
	Total	498.67 cu ft	
	100% excess	498.67 cu ft	
	Total volume	997.34 cu ft	

Yield Per Sack	1.36 cu ft/sk
No: of Sacks	733 sacks

A 20" casing head will be welded to the casing and blow out preventors (BOP's) mounted. A new flow line and drilling nipple suitable to mount air assist drilling equipment will be fabricated and mounted above the BOP's. The BOP'S will be pressure tested to 1000 psi using a test plug in the casing head. If the BOP's will not pressure test, the source of the leak will be located and repaired, or the BOP's will be replaced. Drilling will proceed after testing is completed.

A 17-1/2" diameter hole will be drilled from 245 feet to approximately 1200 feet using water and gel sweeps to keep the hole clean. If necessary, air assisted drilling techniques will be used to drill a portion of the well. Single shot deviation surveys will be run at least once every 300 feet to insure the angle of deviation is less than 3°. During drilling, a mud logger will be on site to collect samples. Samples will be collected no less than once every 30 feet.

Drilling the surface casing hole to 1,200 feet is a major change from previous well construction at BSC. The change is based on the lost circulation zone encountered while drilling in the Trenton formation during the construction of the Galesville monitoring well. After setting surface casing at 950 feet, a major lost circulation zone was encountered at approximately 1,067 feet. To prevent this from re-occurring on this well, the design includes drilling through the Trenton formation and into the top of the Black River formation before setting surface casing. This will isolate any Trenton high porosity/low pressure zones during deeper drilling operations. Special two stage cementing procedures are included to deal with the Trenton should lost circulation occur and to insure the competency of the cement job.

After the well is drilled to 1,200 feet, a complete suite of open hole logs with be run.

SURFACE CONDUCTOR OPEN HOLE LOGGING

Dual Induction- Spontaneous Potential - Gamma Ray 18
Formation Density - Compensated Neutron - Gamma Ray
Open Hole Caliper - Gamma Ray

After the logs are complete, a clean-up trip will be made to clear the hole of any accumulated drilling debris. Casing crews will be rigged up to properly torque and install 19
approximately 1,200 feet of 13-3/8 inch, 54.50 pound/foot, J or K-55, casing. The casing will include a guide shoe with internal float, a float collar, an external casing packer, a sliding sleeve port collar, and sufficient spring steel centralizers to center the casing in the hole. After the casing 20
is installed, inner-string cementing tools will be made up to the drill pipe and run inside of the casing. The lower stinger will be engaged and the casing circulated to clear debris from the hole. 21
The first stage of the cement job is planned to utilize a minimum cement volume equal to no less than 120% of the measured hole volume from total depth to approximately 900 feet. Class A cement with 2% calcium chloride is planned for this stage. After the cement is circulated into place, the inner-string will be moved to inflate the external casing packer. This procedure will isolate additional cement column pressure from being exerted on the Trenton formation. After inflating the external casing packer, the sliding sleeve port collar will be opened and any excess first stage cement will be circulated from the annulus. The second stage cementing will begin immediately after the excess cement is circulated from the hole.

A combination of light weight lead cement and dense tail cement will be used to cement the second stage. Following the cementing procedure, the casing will be hung from the drilling rig for a minimum of 24 hours.

SURFACE CASING:

Surface to 1200 feet

13-3/8", J or K-55, 54.50 lbs/ft, 8rd, ST&C

Drift Diameter:	12.459 inches
O.D. of Coupling:	14.375 inches
Collapse:	1,130 psi
Body Yield	853,000 pounds
Internal Yield	2,730 psi
Joint Strength:	547,000 pounds

SURFACE CASING CEMENTING EQUIPMENT:

Item #	Qty	Description
1.	1	13-3/8" guide shoe with float
2.	1 jt	13-3/8", 54.50 lbs/ft, J or K-55, 8rd, ST&C
	2	Steel spring centralizer, 1- 10' above shoe, 1-10' feet below collar
3.	1	Stab-in float sub
4.	4 jts	13-3/8", 54.50 lbs/ft, J or K 55, 8rd, ST&C
	2	Steel spring centralizer 1 - between joints 2&3, 1- between joints 4&5
	2	Canvas cement baskets on the 10' and 20' from the top of joint 6
5.	2 jts	13-3/8", 54.50 lbs/ft, J or K-55, 8rd, ST&C
6.	1	13-3/8" External Casing Packer
7.	1	13-3/8" Sliding Sleeve Port Collar
8.	23 jts	13-3/8", 54.50 lbs/ft, J or K 55, 8rd, ST&C
	7	Steel spring centralizers, 1 every third joint starting with the top of joint 9

Surface Casing Cement

First Stage

Casing:	13-3/8", J or K-55, 54.50 lbs/ft, ST&C
Cement:	Class A with 2% Calcium Chloride

Hole Diameter	17 1/2"	1.67	cu ft/ ln ft	1.6703
Capacity of open hole annulus	13-3/8" vs 17-1/2"	0.69	cu ft/ ln ft	0.6946
Capacity of cased hole annulus	13-3/8" vs 20"	1.01	cu ft/ ln ft	1.0170
Capacity of 13-3/8" Casing		0.86	cu ft/ ln ft	0.8679

	Top (ft)	Bottom (ft)	Total (ft)
Cased open hole	900	1200	300 feet
Open hole	1200	1210	10 feet

Annular Volume 13-3/8" in 17-1/2"'	208.38 cu ft	300 ft
Hole Volume	16.70 cu ft	10 ft
Volume Left in 13-3/8" casing (40 ft)	34.71 cu ft	
Total	259.79 cu ft	
20% excess	51.95 cu ft	
Total volume	311.75 cu ft	

Yield Per Sack	1.36 cu ft/sk
No. of Sacks	229 sacks

Surface Casing Cement

Second Sage Lead Cement

Cement: Class A Lite

	Size	Volume Constant	
Hole Diameter	171/2"	1.67	cu ft/ln ft
Capacity of open hole annulus	13-3/8" vs 17-1/2"	0.69	cu ft/ ln ft
Capacity of cased hole annulus	13-3/8" vs 20"	1.01	cu ft/ ln ft
Capacity of open hole		1.67	cu ft/ ln ft
Capacity of 13-3/8" Casing		0.86	cu ft/ ln ft

	Top (ft)	Bottom (ft)	Total (ft)
Cased hole depth	0	240	240 feet
Cased open hole	240	700	460 feet

Annular Volume 13-3/8" in 20"	244.56 cu ft
Annular Volume 13-3/8" in 17-1/2"	319.51 cu ft
Total	564.07 cu ft
20% excess	112.81 cu ft
Total volume	676.89 cu ft

Yield Per Sack	2.06 cu ft/sk
No. of Sacks	329 sacks

Surface Casing Cement

Second Stage Tail cement

Cement: Class A with 2% Calcium Chloride

Hole Diameter		17-1/2"		1.67 cu ft/ln ft
Capacity of open hole annulus		13-3/8" vs 17-1/2"		0.69 cu ft/ln ft
Capacity of cased hole annulus		13-3/8" vs 20"		1.02 cu ft/ln ft
Capacity of 13-3/8" Casing				0.87 cu ft/ln ft
	Top (ft)	Bottom (ft)	Total (ft)	
Cased open hole	700	900	200 feet	
Annular Volume 13-3/8" in 17-1/2"		138.92 cu ft		
	Total	138.92 cu ft		
	20% excess	27.78 cu ft		
	Total volume	166.70 cu ft		

Yield Per Sack	1.36 cu ft/sk
No. of Sacks	123 sacks

After waiting 24 hours, the flow line and BOP's will be removed. A casing spool, hanger, and seals will be installed. The BOP's and flow line will be re-installed. After 72 hours of cure time, a cement bond log with variable density will be run. Temp. Log. 23 | 26

Cased Hole Logging Program

Single Pass Temperature

Cement Bond with Variable Density

If the bond log records sufficient cement bond, work will continue. If insufficient cement bonding is shown, a remedial cementing plan will be initiated before drilling out. The casing will be pressure tested to 1000 psi for one hour. If the test pressure changes less than 3%, the casing pressure test will be considered acceptable. If the pressure test does not meet the requirements, the surface pressure control equipment will be investigated to insure the source of the pressure loss is not on the surface. The test will be repeated until the pressure loss is confirmed and quantified. If the casing will not test, a test packer will be used to locate and quantify the leak. After locating and quantifying the leak, a detailed plan will be designed to restore the mechanical integrity of the casing. 27

A 12-1/4 inch diameter drill bit will be used to drill out the float shoe, cement remaining in the casing, and the guide shoe. A 12-1/4 inch hole will be drilled from 1,200 feet to the top of the Precambrian Formation using water, gel sweeps, and possibly air assisted drilling techniques to keep the hole clean of cuttings. The Precambrian is expected to be encountered between 4,300 feet and 4,400 feet. Once the Precambrian is encountered, the 12-1/4" hole will be extended into the formation if it can be easily drilled. No more than 20 feet of Precambrian is expected to be drilled. 28

Two (2) conventional formation cores will be collected during the drilling of the well. A 30-foot core will be taken in the Confining Zone from the approximate depths of 2,095 feet to 2,125 feet. A 30-foot core will be taken in the Injection Interval from the approximate depths of 3,585 feet to 3,615 feet. If the core recovery in either interval is less than 40% of the footage cut, the coring procedure will be evaluated and a second attempt may be recommended for the interval. If adequate core recovery is not obtained, sidewall cores will be obtained from the confining zone and/or injection interval during the open hole logging of the well. 29 33

During the drilling of the Mt. Simon open hole injection interval, three injection interval fracture gradient determination tests will be performed using an anchor testing method. The Mt. Simon injection interval is approximately 1,500 feet thick, and injection interval fracture gradient determination tests will be performed in the upper 500 feet, the middle 500 feet, and the lower 500 feet of the Mt. Simon Injection Interval. The anchor test method will entail drilling to a specified depth and then using only one packer to isolate the testing interval. After reaching a specified test depth, the drill string will be removed from the well and the anchor test assembly installed in the well on the drill string. The isolation packer will be set at the top of the proposed test interval. The test interval is limited to the drilled wellbore below the bottom set depth of the single isolation packer. This method eliminates the possibility of the lower isolation packer failing or breakdown occurring around the lower packer. If the anchor packer fails, the failure will be detectable on surface or by an increase in annular pressure above the test interval.

Either an increasing flow rate step testing or flow rate reduction testing will be used to determine the fracture initiation pressure, fracture propagation pressure, and the fracture closure pressure during each of the three tests. Water will be used during the fracturing tests.

After the drilling is completed, the hole will be circulated clean and then logged. 31

PROTECTION CASING OPEN HOLE LOGGING

- Dual Induction- Spontaneous Potential - Gamma Ray
- Formation Density - Compensated Neutron - Gamma Ray
- Fracture Finder Log (Baker Atlas' Star Tool or equivalent)
- Mechanical Properties Log (Baker Atlas' X Mac Tool, or equivalent tool)
- Open Hole Caliper - Gamma Ray
- Gyroscopic Deviation Survey

A shear sonic tool will be run through the injection zone and confining zone in order to determine the compressional and shear wave travel times of the geologic formations. In combination with the bulk density tool measurements, the dynamic elastic constants (Young's Modulus, Poisson's Ratio, Shear Modulus) can be calculated from the sonic tool data. From the dynamic elastic constants, the far-field stresses (tensile strength, overburden pressure, and fracture pressure) can be calculated and presented as a "mechanical properties log" type display. The mechanical properties presentation can be calibrated to core data and the results of the Mt. Simon open-hole injection interval fracture gradient tests.

A mechanical properties log (Baker Atlas' X Mac Tool, Schlumberger's Full Wave Form Sonic Tool or other equivalent tool) will be run over the injection and confining intervals of the well. The log will be processed to determine the rock properties discussed above.

Following the open hole logging, a straddle packer assembly will be used to recover a
sample of fluid from the upper Mount Simon formation (2,580 feet-2,620 feet). A small inner string will be 43
made up and lowered into the workstring so that nitrogen can be used to produce the fluid. After the fluid 44
is recovered, the well will be allowed to recover and the fluid level measured to determine the bottom hole pressure of the upper Mount Simon.

After the fluid recovery is completed, the straddle packers will be removed from the well bore and a 45
clean-up trip made. Casing crews will be used to properly tighten the 9-5/8 inch protection casing while it 46
is being run into the wellbore. The protection casing will be run to a depth of approximately 2,765 feet. The actual depth will be determined from the logs. It is planned to set the external casing packer immediately below the top of the lower Mount Simon formation. A carbon steel guide shoe will be threaded to a Hastelloy external casing packer and run in the hole beneath the protection casing. The lowermost section of the protection casing will consist of 8-5/8", sch 40 or sch 80 Hastelloy C-276. A polished bore casing receptacle made from 8-5/8", sch 80, Hastelloy C-276 pipe will be run next. A cross over will connect the Hastelloy to the 9-5/8", 40#/ft, N-80 carbon steel casing. Another external casing packer and sliding sleeve port collar will be installed at approximately 2,050 feet. Once the casing is in place, an inner string with port collar tools will be lowered into the casing. The well will be circulated clean. The lower section of the casing from 2,765 feet to 2,050 feet will be cemented with Epseal epoxy resin cement. The upper section of casing from 2,050 feet to surface will be cemented with a combination 48
of Class A cement and Class A Lite cement.

PROTECTION CASING: Surface to 2,700 feet

9-5/8", N-80, 40 lbs/ft, 8rd, LT&C

Drift Diameter:	8.679 inches
O.D. of Coupling:	10.625 inches
Collapse:	3,090 psi
Body Yield	916, 000 pounds
Internal Yield	5,750 psi
Joint Strength:	737,000 pounds

ACID RESISTANT CASING AND POLISHED BORE RECEPTACLE:

8-5/8" Hastelloy C-276, Sch-80 with "O" ring sealed square acme threads. Total length ± 40 feet. Set 2,700 to 2,740 feet. Total BHA with sliding sleeve, external casing packer and guide shoe: ±2755 feet. I.D. of PBR: 7.75 inches

PROTECTION CASING CEMENTING EQUIPMENT

Item #	Qty	Description
1.	1	8-5/8" External Casing Packer with guide shoe.
2.	1	8-5/8" Hastelloy Sliding Sleeve Port Collar
3.	1	8-5/8" Hastelloy PBR Extension
4.	1	8-5/8" Hastelloy Polished Bore Receptacle
5.	1	8-5/8" by 9-5/8" cross over sub
6.	17 jts	9-5/8", 40 lbs/ft, N-80, 8rd, LT&C
	3	8-5/8" Steel spring centralizer, 1- 10` above port collar, 1 on extension, 1 on PBR
	8	9-5/8" Steel Spring Centralizer, 1 on every other joint
7.	1	9-5/8" External casing Packer
8.	1	9-5/8", Sliding Sleeve Port Collar
9.	51 jts	9-5/8", 40 lbs/ft, N.-80, 8rd, LT&C
	17	9-5/8" Steel Spring Centralizer, 1 on every third joint

Protection Casing Cement

First Stage

Cement: Epseal Epoxy Resin Slurry

Hole Diameter	12-1/4"			1.67 cu ft/ln ft X 0.8185	
Capacity of open hoe annulus	9-5/8" vs 12-1/4"			0.69 cu ft/ln ft X 0.7132	234 gals/ln ft 2.3428
Capacity of open hole annulus	8-5/8" vs 12-1/4"				3.09 gals/ln ft 3.0574
	TOP (ft)	Bottom (ft)	Total (ft)		
Cased hole depth	0	0	0 feet		
Cased open hole 9-5/8"	2050	2625	575 fleet	should be 2705 ? 2700 ?	
Cased open hole 8-5/8"	2625	2665	40 feet		

Annular Volume 9-5/8" in 12-1/4"	1347.11 gals ✓
Annular Volume 8-5/8" in 12-1/4"	123.50 gals ✓
Total	1470.61 gals ✓
10% excess	147.06 gals ✓
Total volume	1617.67 gals ✓

Protection Casing Cement

Second Stage Lead

Cement Class A Lite

Hole Diameter	12-1/4"		0.82 car ft/ln ft
Capacity of open hole annulus	9-5/8" vs 12 1/4"		0.31 cu ft/ln ft 0.3172
Capacity of cased hole annulus	9-5/8" vs 13.3/8"'		0.36 cu ft/ln ft 0.3622
Capacity of 9-5/8" Casing			0.87 cu ft/ln ft

	Top (ft)	Bottom (ft)	Total (ft)
Cased hole depth	0	1200	1200 feet
Cased open hole 9-5/8"	1200	1850	650 feet

Annular Volume 9-5/8" in 12- 1/4" .	203.58 cu ft
Annular Volume 9-5/8" in 13-3/8"	435.24 cu ft
Total	638.82 cu ft
20% excess	127.76 cu ft
Total volume	766.58 cu ft

Yield Per Sack	2.06 cu ft/sk
No. of Sacks	372 sacks

Protection Casing Cement

Second Stage Tail

Cement: Class A with 2% Calcium Chloride

Hole Diameter	12-1/4"		
Capacity of open hole annulus	9-5/8" vs 12-1/4"		0.31 cu ft/ln ft 0.3172
Capacity of open hoe	12-1/4"		0.82 cu ft/ln ft 0.8185
Cased open hole 9-5/8"	1850	2050	200 Total feet

Annular Volume 9-5/8" in 12-1/4"	62.64 cu ft
20% excess	12.53 cu ft
Tots volume	75.17 cu ft

Yield Per Sack	2.06 cu ft/sk
No. of Sacks	36 sacks .

The casing will be hung from the drilling-rig for a minimum of twenty-four hours while the cement is initially allowed to cure. After twenty-four-hours has expired, the casing will be cut, the BOP's removed, a 9-5/8 inch hanger, seal, and a tubing spool installed. The cement will be allowed to cure for 72 total hours after pumping. A logging truck will be rigged up to run the following logs:

CASED HOLE LOGGING PROGRAM (72 hours after cementing)

Cement Bond with Variable Density

Temperature Log

Electro-Magnetic Casing Inspection

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After logging, a test seal will be connected to the bottom of the work string and lowered into the casing polished bore receptacle. The casing will be pressure tested to 1000 psi for one hour. If the test pressure does not change more than 3% during the hour, the test will be considered acceptable. After pressure testing, the well bore will be stimulated by nitrogen jetting, acidizing and nitrogen jetting. During the first jetting phase, samples of formation fluid will be collected.

After stimulation, an injectivity/fall-off test will be performed followed by a radioactive tracer log. The logging tools will be rigged down and casing crews rigged up to install the 5-1/2" fiberglass injection tubing.

TUBING:

Surface to 2775 feet

5-1/2", Red Box 2500, 7.3 lbs/ft, 8rd, LT&C

Drift Diameter.	5.53 inches
O.D. of Coupling:	6.78 inches
Collapse:	3,300 psi
Internal Yield	2,500 psi
Joint Strength:	54,500 pounds

Once the tubing is run, the tubing will be spaced out and the annulus filled with inhibited NaCl brine. The seal assembly will be landed in the polished bore receptacle. The annulus will be topped off with food grade mineral oil. The BOP's will be removed and the tubing hung off in the tubing spool. The annulus will be pressure tested to 1000 psi for one hour. If the test pressure changes less than 3% during the hour, the test will be considered acceptable.

The drilling rig will be rigged down and removed from location. The location will be cleared and construction will begin on the surface facilities. A report fully detailing the work will be prepared and submitted to the USEPA along with a modification request to the current petition for exemption from the Land ban regulations.

September 18, 2001
Ref: PF/UIC/DW

Bethlehem Steel Corporation
Burns Harbor Division

Additional Information for WAL/SPL Well Application
UIC Permit Number IN-127-1W-0007

Attachment 2 - Revised Drilling Program
(Revised Appendix A of March 24, 1999 Permit Application)

BETHLEHEM STEEL CORPORATION
BURNS HARBOR DIVISION
WAL/SPL-1

DRILLING PROGRAM

STEP	TASK
1.	Prepare the location by removing as much miscellaneous equipment from the area as possible.
2.	Survey the location and stake the well site.
3.	Drive a 30 inch diameter, 0.375 inch or .500 inch wall carbon steel conductor to 40 feet or refusal.
4.	Move in and rig up the drilling rig with all the necessary ancillary equipment. The rig should include a substructure with rotary table, two sets of pipe racks, catwalk and V-door, two steel tanks, two mud pumps, dog house, adequate generators for the mud system and the rig, drilling instrumentation and slick line.
5.	Set up a closed mud system which includes shakers, de-sander, de-silter and centrifuge. All drill cuttings will be placed in roll off boxes for disposal.
6.	Drill the rat hole and mouse hole.
7.	Drill a 26-inch hole to approximately 245 feet using water and native mud. A single shot-deviation survey will be made every third joint drilled (approximately 100 feet).
8.	Circulate and condition the hole for casing.
9.	Install approximately 240 feet of 20 inch, 94 pounds/foot, J or K-55, 8rd, ST&C casing with a sting in guide shoe and float.
10.	Pick up an inner-string and stab into the guide shoe.
11.	Circulate the hole clean.
12.	Cement the casing with Class A cement with 2% calcium chloride. The calculated volume plus 100% excess will be emplaced. After cementing the casing, clean out any excess cement from the cellar. If the cement fails to come to surface, top off the annulus by the tremie method using Class A cement.
13.	Allow the cement to cure for 24 hours while hanging from the rig.

14. Cut off the excess casing. Weld on a casing head. Mount a blow out preventer (BOP) and flow line. Move in and rig a mud logger to catch and describe drilling samples.

15. Pressure test the BOP to 1000 psi using a test plug. If the BOP's will not pressure test, the source of the leak will be located and repaired or the BOP's will be replaced.

16. A 17-1/2 inch bit will be used to drill the surface hole. The well will be drilled using fresh water. High viscosity gel-lime sweeps will be made every 100 feet, if needed. Pick up a 17-1/2 inch bit with sufficient drill collar weight.

17. Drill the surface hole to 1,200 feet. Catch wet and dry drilled cutting samples every 30 feet. Take a single shot survey approximately every 300 feet. The maximum deviation in the well will be 3 degrees or less.

18. Circulate and condition the hole for logs. Rig up the electric loggers. Run the following electric logs from 1200 feet to surface:
    A) Dual Induction - Spontaneous Potential - Gamma Ray
    B) Formation Density - Compensated Neutron - Gamma Ray
    C) Open Hole Caliper - Gamma Ray

19. Circulate and condition the hole for casing. Drift the casing on the racks when it arrives, clean and visually inspect all the threads on the pins and couplings. Rig up to run the 13-3/8 inch, 54.5 lb/ft, J or K-55 casing to approximately 1,200 feet.

20. Pick up and run the inner-string and stab in guide.

21. Rig up to cement. Circulate one annulus volume of clean water prior to cementing. Cement from 1,200 feet to surface following the attached cementing program.

22. Allow the cement to cure for a minimum of 24 hours while hanging from the slips.

23. Cut off the casing to the proper height and mount a casing spool, hanger, and seals.

24. Nipple up the BOP. Function test the BOP. Pressure test the BOP and lines to 2,000 psig using a test plug. If the BOP's will not pressure test, the source of the leak will be located and repaired or the BOP's will be replaced.

25. Wait on cement for 72 hours prior to cased hole logging operations.

26. Rig up the electric loggers and run the following electric logs from casing plug back TD to surface:
    A. Cement Bond log with Variable Density
    B. Temperature Log

27. Pressure test the casing to 1000 psi for one hour. The test will be considered successful if there is less than a 3% gain or loss in pressure after one hour. If the pressure test is not acceptable, the surface pressure control equipment will be investigated to make sure the source of the pressure loss is not on the surface. The test will be repeated until the pressure loss is confirmed and quantified. If the casing will not pass the required pressure test, a test packer will be located and ordered. A series of pressure tests will be performed on the casing using the test packer to locate and quantify the source of the casing leak. After identifying the location of the leak, a detailed plan will be designed and performed to restore the mechanical integrity of the casing string. After the remedial procedure is complete, the casing will be pressure tested to the 1000 psi for one hour.

28. Pick up a 12-1/4 inch bit and bottomhole assembly and run in the well with the drill pipe. Drill out the surface casing. Do not exceed 10,000 lbs bit weight or 50 rpm rotary while drilling out the float and shoe.

29. Drill a 12-1/4 inch hole from approximately 1,200 feet to the depth of the first scheduled conventional formation core at approximately 2,095 feet in the Confining Zone. A 30-foot core will be taken from approximately 2,095 feet to 2,125 feet.

    Catch wet and dry samples every 30 feet. Take a single shot survey every tenth joint drilled (approximately every 300 feet). The maximum deviation will be 3 degrees or less.

30. Ream the cored interval to 12-1/4 inches and drill a 12-1/4 inch hole from approximately 2,125 feet to the depth of the first scheduled injection interval fracture gradient determination tests. The first test will be selected in the upper 500 feet of the injection interval between 2,740 feet and 3,240 feet.

    Catch wet and dry samples every 30 feet. Take a single shot survey every tenth joint drilled (approximately every 300 feet). The maximum deviation will be 3 degrees or less.

31. Circulate and condition the hole for the anchor fracture gradient determination test. Pull out of the well with the 12-1/4-inch bit and drilling assembly. Install the anchor fracture gradient determination test assembly on the drill string.

32. Perform open hole fracture gradient testing in the upper Mt. Simon formation as described in the fracture gradient test plan.

33. Drill a 12-1/4 inch hole from the depth of the first fracture gradient determination test to the depth of the second scheduled conventional formation core at approximately 3,585 feet in the Injection Interval. A 30-foot core will be taken from approximately 3,585 feet to 3,615 feet.

    Catch wet and dry samples every 30 feet. Take a single shot survey every tenth joint drilled (approximately every 300 feet). The maximum deviation will be 3 degrees or less.

34. Ream the cored interval to 12-1/4 inches and drill a 12-1/4 inch hole from approximately 3,615 feet to the depth of the second scheduled injection interval fracture gradient determination tests. The second test will be selected in the middle 500 feet of the injection interval between the depths of 3,615 feet and 3,740 feet.

    Catch wet and dry samples every 30 feet. Take a single shot survey every tenth joint drilled (approximately every 300 feet). The maximum deviation will be 3 degrees or less

35. Circulate and condition the hole for the anchor fracture gradient determination test. Pull out of the well with the 12-1/4-inch bit and drilling assembly. Install the anchor fracture gradient determination test assembly on the drill string.

36. Perform open hole fracture gradient testing in the middle Mt. Simon formation as described in the fracture gradient test plan.

37. Drill the 12-1/4 inch hole from approximately the depth of the second fracture determination test to the depth of the third scheduled injection interval fracture gradient determination tests. The third test will be selected in the lower 500 feet of the injection interval between 3,740 feet and 4,240 feet.

    Catch wet and dry samples every 30 feet. Take a single shot survey every tenth joint drilled (approximately every 300 feet). The maximum deviation will be 3 degrees or less.

38. Circulate and condition the hole for the anchor fracture gradient determination test. Pull out of the well with the 12-1/4-inch bit and drilling assembly. Install the anchor fracture gradient determination test assembly on the drill string.

39. Perform open hole fracture gradient testing in the lower Mt. Simon formation as described in the fracture gradient test plan.

40. Pull out of the well with the fracture determination assembly.

41. Drill the 12-1/4 inch hole from the depth of the third fracture determination test to approximately 4,400 feet. Circulate and condition the wellbore to run the open hole logs on the well.

42. Rig up the electric loggers. Run the following electric logs from approximately 4,400-feet to 1,200 feet:

    A. Dual Induction - Spontaneous Potential - Gamma Ray

    B. Formation Density - Compensated Neutron- Gamma Ray

    C. Fracture Finder Log (Baker Atlas' Star Tool, Schlumberger's Formation Microscanner or equivalent)

    D. Open Hole Caliper - Gamma Ray

    E. Mechanical Properties Log (Baker Atlas' X Mac Tool, Schlumberger's Full Wave Form Sonic Tool, or equivalent)

    F. Gyroscopic survey from surface to total depth

43. Pick up a straddle packer assembly for recovering a fluid sample from the upper Mt. Simon formation. The sample will be collected between the approximate depths of 2,580 feet and 2,620 feet.

44. Recover a fluid sample from the upper Mt. Simon formation using the straddle packers, an inner string and nitrogen jetting.

45. Release the packer and pull out of the hole. Lay down the inflatable open hole tools.

46. Run in the hole with the drill string to circulate and condition the hole for casing. Pull out of the hole laying down.

47. Drift the casing on the racks when it arrives, clean and visually inspect all the threads on the pins and couplings. Rig up to run the 9-5/8 inch, 40 lb/ft N-80 casing to 2,765 feet, per the casing and cementing equipment programs.

48. Run in the hole with the TAM cementing tools on drill pipe. Cement per the cementing program.

49. Cut off the casing to the proper height and install the hanger, casing spool, and seals after 24 hours of waiting for the cement to cure.

50. Nipple up the BOP. Function test the BOP. Pressure test the BOP and lines to 2,000 psig.

51. Wait on cement for 72 hours prior to cased hole logging operations.

52. Rig up the electric loggers and run the following electric logs from casing plug back TD to surface:
    A. Temperature Log
    B. Cement Bond Log with Variable Density
    C. Electro Magnetic Casing Inspection Log
    D. Radioactive Tracer

53. Pick up an inflatable packer or *test seal* on the drill pipe, go in the hole and set the packer 10 feet above the casing shoe. Pressure test the casing to 1000 psi for one hour. If the pressure changes less than 3% in the one hour period, the test will be considered successful. If the pressure test is not acceptable, the surface pressure control equipment will be investigated to make sure the source of the pressure loss is not on the surface. The test will be repeated until the pressure loss is confirmed and quantified. If the casing will not pass the required pressure test, a test packer will be located and ordered. A series of pressure tests will be performed on the casing using the test packer to locate and quantify the source of the casing leak. After identifying the location of the leak, a detailed plan will be designed and performed to restore the mechanical integrity of the casing string. After the remedial procedure is complete, the casing will be pressure tested to the 1000 psi for one hour.

54. A fluid sample will be collected from the Mt. Simon open hole injection interval with jetting techniques using coiled tubing and nitrogen. The pH, specific gravity, conductivity, and temperature of the fluid recovered from the well will be monitored to determine when the fluid from the formation has stabilized. After the fluid stabilizes, the fluid sample will be collected.

55. Stimulate the well as described in the stimulation plan.

56. Pull out of the hole and lay down the work string.

57. Rig up and run the seal assembly and 5-1/2" fiberglass injection tubing. Tag up and space out.

58. Displace the tubing/longstring casing annulus with inhibited NaCl brine and top off with food grade mineral oil for freeze protection (approximately 30 feet of mineral oil).

59. Hang off the tubing in the wellhead.

60. Pressure test the annulus to 1000 psi for one hour. If the annulus pressure changes less than 3% after one hour, the test will be considered acceptable. If the pressure test is not acceptable, the surface pressure control equipment will be investigated to make sure the source of the pressure loss is not on the surface. The test will be repeated until the pressure loss is confirmed and quantified. If the well will not pass the standard annulus pressure test (SAPT), a detailed plan will be designed and performed to investigate and restore the mechanical integrity of the well. After the remedial procedure is complete, the SAPT will be performed at 1000 psi for one hour.

61. Clean the mud system and dispose of fluids and drilled solids properly. Rig down the drilling rig and move off.

BETHLEHEM STEEL CORPORATION
BURNS HARBOR DIVISION
WAL/SPL-1
LOGGING PROGRAM

Surface Hole

Open Hole
- Dual Induction- Spontaneous Potential-Gamma Ray
- Formation density-Compensated Neutron-Gamma ray
- Open Hole Caliper- Gamma Ray

Cased Hole (72 hours after cementing)
- Cement Bond with Variable Density
- Temperature Log

Protection Hole

Open Hole
Dual Induction- Spontaneous Potential-Gamma Ray
Formation density-Compensated Neutron-Gamma ray
Fracture Finder Log (Baker Atlas' Star Tool or Equivalent)
Mechanical Properties Log (Baker Atlas' X Mac Tool or Equivalent)
Open Hole Caliper- Gamma Ray
Gyroscopic Survey

Cased Hole (72 hours after cementing)
- Cement Bond with Variable Density
- Temperature Log
- Electro-Magnetic Casing Inspection
- Radioactive Tracer

BETHLEHEM STEEL CORPORATION
BURNS HARBOR DIVISION
WAL/SPL-1
CASING PROGRAM AND SPECIFICATIONS

CONDUCTOR: Surface to 40' or point of refusal
30", .375" or .500" wall, carbon steel

SURFACE CONDUCTOR:

Surface to 240 feet
20", J-55, 94 lbs/ft, 8rd, ST&C

Drift Diameter:	18.936 inches
O.D. of Coupling:	21.000 inches
Collapse:	520 psi
Body Yield	1,480,000 pounds
Internal Yield	2,110 psi
Joint Strength:	784,000 pounds

SURFACE CASING: Surface to 970 feet
13-3/8", J or K-55, 54.50 lbs/ft, 8rd, ST&C

Drift Diameter:	12.459 inches
O.D. of Coupling:	14.375 inches
Collapse:	1,130 psi
Body Yield	853,000 pounds
Internal Yield	2,730 psi
Joint Strength:	547,000 pounds

PROTECTION CASING: Surface to 2700 feet
9-5/8", N-80, 40 lbs/ft, 8rd, LT&C

Drift Diameter:	8.679 inches
O.D. of Coupling:	10.625 inches
Collapse:	3,090 psi
Body Yield	916,000 pounds
Internal Yield	5,750 psi
Joint Strength:	737,000 pounds

ACID RESISTANT CASING AND POLISHED BORE RECEPTACLE:

8" Hastelloy C-276, Sch-80 with "O"ring sealed square acme threads. Total length ± 40 feet. Set 2700 to 2740 feet. Total BHA with sliding sleeve, external casing packer and guide shoe: ± 2755 feet. I.D. of PBR: 7.75 inches

TUBING:

Surface to 2775 feet
5-1/2", Red Box 2500, 7.3 lbs/ft, 8rd, LT&C

Drift Diameter:	5.53 inches
O.D. of Coupling:	6.78 inches
Collapse:	3,300 psi
Internal Yield	2,500 psi
Joint Strength:	54,500 pounds

BETHLEHEM STEEL CORPORATION
BURNS HARBOR DIVISION
WAL/SPL-1
CEMENTING EQUIPMENT

Surface Conductor

Item #	Qty	Description
1.	1	20" guide shoe with float
2.	1 jt	20", 94 lbs/ft, J or K-55, 8rd, ST&C
	2	Steel spring centralizer, 1- 10' above shoe, 1-10'feet below collar
3.	1	Stab-in float sub
4.	5 jts	20", 94 lbs/ft, J or K-55, 8rd, ST&C
	2	Steel spring centralizer 1- between joints 3&4, 1- between joints 1&2

Surface Casing

Item #	Qty	Description
1.	1	13-3/8" guide shoe with float
2.	1 jt	13-3/8", 54.50 lbs/ft, J or K-55, 8rd, ST&C
	2	Steel spring centralizer, 1- 10' above shoe, 1-10'feet below collar
3.	1	Stab-in float sub
4.	4 jts	13-3/8", 54.50 lbs/ft, J or K-55, 8rd, ST&C
	2	Steel spring centralizer 1 - between joints 2&3, 1- between joints 4&5
	2	Canvas cement baskets on the 10' and 20' from the top of joint 5
5.	2 jts	13-3/8", 54.50 lbs/ft, J or K-55, 8rd, ST&C
6.	1	13-3/8" External Casing Packer
7.	1	13-3/8" Sliding Sleeve Port Collar
8.	23 jts	13-3/8", 54.50 lbs/ft, J or K-55, 8rd, ST&C
	7	Steel spring centralizers, 1 every third joint starting with the top of joint 8

Protection Casing

Item #	Qty	Description
1.	1	8-5/8" External Casing Packer with guide shoe.
2.	1	8-5/8" Hastelloy Sliding Sleeve Port Collar
3.	1	8-5/8" Hastelloy PBR Extension
4.	1	8-5/8" Hastelloy Polished Bore Receptacle
5.	1	8-5/8" by 9-5/8" cross over sub
6.	17 jts	9-5/8", 40 lbs/ft, N-80, 8rd, LT&C
	3	8-5/8" Steel spring centralizer, 1- 10' above port collar, 1 on extension, 1 on PBR
	8	9-5/8" Steel Spring Centralizer, 1 on every other joint
7.	1	9-5/8" External casing Packer
8.	1	9-5/8", Sliding Sleeve Port Collar
9.	51jts	9-5/8", 40 lbs/ft, N-80, 8rd, LT&C
	17	9-5/8" Steel Spring Centralizer, 1 on every third joint

Bethlehem Steel Corporation
Burns Harbor Division
WAL/SPL #1 Cement Calculations:

All capacities, volumes, pipe weights, diameters, etc. were obtained from Halliburton Cementing Tables per standard API practice.

Surface Conductor Cement:
Casing: 20", J-55, 94 lbs/ft, ST&C
Cement: Class A with 2% Calicum Chloride

		Size			Volume Constant
Hole Diameter		26"			3.69 cu ft/ ln ft
Capacity of open hole annulus		20" vs 26"			1.51 cu ft/ ln ft
Capacity of cased hole annulus		20" vs 30"			2.48 cu ft/ ln ft
Capacity of 20" Casing					1.99 cu ft/ ln ft
	Top (ft)	Bottom (ft)	Total		
Cased hole depth	0	40		40	feet
Cased open hole	40	240		200	feet
Open hole	240	245		5	feet

Annular Volume	20" vs 30"	99.39	cu ft	40 ft* 2.4847 cu ft/ln ft
Annular Volume	20" vs 26"	301.06	cu ft	200 ft *1.5053 cu ft/ln ft
Hole Volume	26"	18.44	cu ft	5 ft * 3.687 cu ft/ln ft
Volume Left in 20" casing (40 feet)		79.79	cu ft	40 ft * 1.9947 cu ft/ln ft
	Total	498.67	cu ft	
	100% excess	498.67	cu ft	
	Total volume	997.34	cu ft	

Yield Per Sack	1.36	cu ft/sk
No. of Sacks	733	sacks

Surface Casing Cement:

First Stage

Casing: 13-3/8", J or K-55, 54.50 lbs/ft, ST&C
Cement: Class A with 2% Calcium Chloride

Hole Diameter		17 1/2"			1.67 cu ft/ ln ft
Capacity of open hole annulus		13-3/8" vs 17-1/2"			0.69 cu ft/ ln ft
Capacity of cased hole annulus		13-3/8" vs 20"			1.02 cu ft/ ln ft
Capacity of 13-3/8" Casing					0.87 cu ft/ ln ft
	Top (ft)	Bottom (ft)	Total (ft)		
Cased open hole	900	1200	300	feet	
Open hole	1200	1210	10	feet	

Annular Volume 13-3/8" in 17-1/2"	208.38	cu ft
Hole Volume	16.70	cu ft
Volume Left in 13-3/8" casing (40 ft)	34.72	cu ft
Total	259.80	cu ft
20% excess	51.96	cu ft
Total volume	311.76	cu ft

Yield Per Sack	1.36	cu ft/sk
No. of Sacks	229	sacks

Surface Casing Cement

Second Stage Lead cement

Cement: Class A Lite

		Size			Volume Constant
Hole Diameter		17 1/2"			1.67 cu ft/ ln ft
Capacity of open hole annulus		13-3/8" vs 17-1/2"			0.69 cu ft/ ln ft
Capacity of cased hole annulus		13-3/8" vs 20"			1.02 cu ft/ ln ft
Capacity of open hole					1.67 cu ft/ ln ft
Capacity of 13-3/8" Casing					0.87 cu ft/ ln ft
	Top (ft)	Bottom (ft)	Total (ft)		
Cased hole depth	0	240	240	feet	
Cased open hole	240	700	460	feet	

Annular Volume 13-3/8" in 20"	244.56	cu ft
Annular Volume 13-3/8" in 17-12"	319.52	cu ft
Total	564.08	cu ft
20% excess	112.82	cu ft
Total volume	676.89	cu ft

Yield Per Sack	2.06	cu ft/sk
No. of Sacks	329	sacks

Surface Casing Cement

Second Stage Tail cement

Cement: Class A with 2% Calicum Chloride

Hole Diameter	17 1/2"	1.67 cu ft/ ln ft
Capacity of open hole annulus	13-3/8" vs 17-1/2"	0.69 cu ft/ ln ft
Capacity of cased hole annulus	13-3/8" vs 20"	1.02 cu ft/ ln ft
Capacity of 13-3/8" Casing		0.87 cu ft/ ln ft

	Top (ft)	Bottom (ft)	Total (ft)
Cased open hole	700	900	200 feet

Annular Volume 13-3/8" in 17-12"	138.92	cu ft
Total	138.92	cu ft
20% excess	27.78	cu ft
Total volume	166.70	cu ft

Yield Per Sack	1.36	cu ft/sk
No. of Sacks	123	sacks

Protection Casing Cement

First Stage

Cement: Epseal Epoxy Resin Slurry

Hole Diameter		12-1/4"		1.67 cu ft/ ln ft	
Capacity of open hole annulus		9-5/8" vs 12-1/4"		0.69 cu ft/ ln ft	2.34 gals/ln ft
Capacity of open hole annulus		8-5/8" vs 12-1/4"			3.09 gals/ln ft
	Top (ft)	Bottom (ft)	Total (ft)		
Cased hole depth	0	0	0 feet		
Cased open hole 9-5/8"	2050	2625	575 feet		
Cased open hole 8-5/8"	2625	2665	40 feet		

Annular Volume 9-5/8" in 12-1/4"	1347.11 gals
Annular Volume 8-5/8" in 12-1/4"	123.50 gals
Total	1470.61 gals
10% excess	147.06 gals
Total volume	1617.67 gals

Protection Casing Cement

Second Stage Lead

Cement: Class A Lite

Hole Diameter		12-1/4"		0.82 cu ft/ ln ft
Capacity of open hole annulus		9-5/8" vs 12-1/4"		0.31 cu ft/ ln ft
Capacity of cased hole annulus		9-5/8" vs 13-3/8"		0.36 cu ft/ ln ft
Capacity of 9-5/8" Casing				0.87 cu ft/ ln ft
	Top (ft)	Bottom (ft)	Total (ft)	
Cased hole depth	0	1200	1200 feet	
Cased open hole 9-5/8"	1200	1850	650 feet	

Annular Volume 9-5/8" in 12-1/4"	203.58 cu ft
Annular Volume 9-5/8" in 13-3/8"	435.24 cu ft
Total	638.82 cu ft
20% excess	127.76 cu ft
Total volume	766.58 cu ft

Yield Per Sack	2.06 cu ft/sk
No. of Sacks	372 sacks

Protection Casing Cement

Second Stage Tail

Cement: Class A with 2% Calciuum Chloride

Hole Diameter		12-1/4"		
Capacity of open hole annulus		9-5/8" vs 12-1/4"		0.31 cu ft/ ln ft
Capacity of open hole		12-1/4"		0.82 cu ft/ ln ft
Cased open hole 9-5/8"	1850	2050	200 Total feet	

Annular Volume 9-5/8" in 12-1/4"	62.64	cu ft
20% excess	12.53	cu ft
Total volume	75.17	cu ft

Yield Per Sack	2.06 cu ft/sk
No. of Sacks	36 sacks

APPENDIX B
DATA FOR CALCULATIONS OF PLUGGING AND ABANDONMENT COSTS

March 9, 1999
#5a:\J021uic-99.doc

PLUGGING AND ABANDONMENT COST ESTIMATE

Subject: Burns Harbor Division
Underground Injection Wells

1. Annual (Average) Producer Price Index for Oil and Gas Field Machinery (Commodity Code 11-91) from U.S. Department of Labor (202-606-7705). Values are taken from the Internet at **http://stats.bls.gov** (see Attachment):

   1997 - 122.8
   1998 - 125.8

2. Inflation Factor = 1998 Index/1997 Index
   (1999) = 125.8/122.8
   = 1.024

3. 1999 plugging and abandonment cost estimate is calculated by adjusting the 1998 cost estimates for inflation based on the above price index:

WPL #1	$163,000	x	1.024	=	166,900
WAL #1	$ 94,600	x	1.024	=	96,900
WAL #2	$ 94,600	x	1.024	=	96,900
GSMW*	$ 87,200	x	1.024	=	89,300
TOTAL					**$450,000**

* GSMW = Galesville Sandstone Monitoring Well

4. Attached is a table showing the history of the cost estimates from 1986 to 1999.

D. L. Holmes

D. L. Holmes

BURNS HABOR DIVISION
UNDERGROUND INJECTION CONTROL (UIC) WELLS
PLUGGING AND ABANDONMENT COST ESTIMATES - $

YEAR	INFLATION FACTOR	WPL #1	WAL #1	WAL #2	GSMW	TOTAL
1986	*	46,500	36,200	36,200	--	118,900
1987	0.973	45,300	35,200	35,200	--	115,700
1988	0.989	44,800	34,850	34,850	--	114,500
1989	1.041	46,600	36,300	36,300	--	119,200
1990	**	x 2.8 131,000	x 3.09 76,000	76,000	70,000	353,000
1991	1.033	135,500	78,500	78,500	72,500	365,000
1992	1.060	144,000	83,000	83,000	77,000	387,000
1993	0.991	142,500	82,500	82,500	76,000	383,500
1994	1.006	143,400	83,300	83,300	76,700	386,700
1995	1.024	146,900	85,300	85,300	78,600	396,100
1996	1.031	151,500	88,000	88,000	81,100	408,600
1997	1.032	156,400	90,800	90,800	83,700	421,700
1998	1.042	163,000	94,600	94,600	87,200	439,400
1999	1.024 =1998/1657	166,900	96,900	96,900	89,300	450,000
2000	1.005	167,700	97,100	97,400	89,700	452,200 +SPL/WAL #1

* Initial cost estimate.
** Revised cost estimate.
WPL = Waste Pickle Liquor
WAL = Weak Ammonia Liquor
GSMW = Galesville Sandstone Monitoring Well

MAR. 9.1999

FAX

Bureau of Labor Statistics

Producer Price Index
2 Massachusetts Ave. NE
Postal Square Building
Suite 3840
Washington, DC 20212

To:	Don Holmes
Company:	
Fax number:	+1 (610) 694-1524
Business phone:	
From:	William F. Snyders
Fax number:	(202) 606-7754 or (202) 606-7753
Business phone:	(202) 606-7705
E-mail address:	Snyders_W@bls.gov
Date & Time:	2/26/99 8:55:09 AM
Pages:	2
Re:	

Bureau of Labor Statistics Data

Data extracted on: February 26, 1999 (08:54 AM)

Producer Price Index-Commodities

Series Catalog:

Series ID : wpu1191

Not Seasonally Adjusted
Group : Machinery and equipment
Item : Oil field and gas field machinery
Base Date : 8200

Data:

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
1989	97.9	97.9	98.1	98.2	98.5	98.6	99.3	100.1	100.2	100.5	100.2	100.1	99.1
1990	100.7	100.5	100.6	100.7	100.6	100.9	101.2	102.0	104.7	104.9	105.8	106.1	102.4
1991	106.2	106.8	107.8	107.9	109.0	109.0	109.4	109.3	109.3	109.3	109.3	109.3	108.6
1992	109.3	107.6	107.6	107.6	107.7	107.9	107.3	106.8	107.3	106.9	107.9	108.0	107.6
1993	108.2	108.1	108.4	107.6	108.1	107.5	107.3	107.3	108.0	108.9	109.0	109.8	108.2
1994	109.8	110.6	110.4	110.4	110.0	110.2	110.6	110.5	110.8	111.9	111.9	111.9	110.8
1995	112.4	112.6	113.2	113.3	113.3	113.6	114.5	114.6	114.7	115.6	115.8	115.8	114.1
1996	116.9	117.0	117.0	117.1	117.1	117.8	118.0	118.0	118.1	118.5	118.8	119.4	117.8
1997	120.9	121.3	122.1	122.4	122.5	122.7	122.8	123.0	123.2	124.0	124.8	124.7	122.8
1998	125.7	125.6	125.7	125.6	125.6	125.6	125.6	125.9	125.9	126.1(P)	126.4(P)	126.4(P)	125.8(P)
1999	126.6(P)												

P : Preliminary. All indexes are subject to revision four months after original publication.

Data Home Page

BLS Home Page

Bureau of Labor Statistics
ppi-info@bls.gov

June 10, 1998
#5a:\J021uic.doc

PLUGGING AND ABANDONMENT COST ESTIMATE

Subject: Burns Harbor Division
Underground Injection Wells

1. Annual (Average) Producer Price Index for Oil and Gas Field Machinery (Commodity Code 11-91) from U.S. Department of Labor (202-606-7705). Values are taken from the Internet at **http://stats.bls.gov** (see Attachment #4):

   1996 - 117.8
   1997 - 122.8

2. Inflation Factor = 1997 Index/1996 Index
   (1998) = 122.8/117.8
   = 1.042

3. 1998 plugging and abandonment cost estimate is calculated by adjusting the 1997 cost estimates for inflation based on the above price index:

WPL #1	$156,400	x	1.042	=	163,000
WAL #1	$ 90,800	x	1.042	=	94,600
WAL #2	$ 90,800	x	1.042	=	94,600
GSMW*	$ 83,700	x	1.042	=	87,200
TOTAL					**$439,400**

* GSMW = Galesville Sandstone Monitoring Well

4. Attachment #2 is a table showing the history of the cost estimates from 1986 to 1998.

D.L. Holmes

D. L. Holmes

ATTACHMENT L/M - CONSTRUCTION PROCEDURES and CONSTRUCTION DETAILS

WAL/SPL-1 will be constructed utilizing procedures and materials that insure that the well is suitable for injection of either WAL or SPL. Proposed construction procedures and materials are discussed in this attachment. A schematic diagram of the proposed construction details of WAL/SPL-1 is included as Figure 3-4. This figure also compares the proposed well configuration to a stratigraphic column of the sub-surface geology expected at the proposed location. A wellhead schematic is included as Figure 3-5.

This attachment consists of six (6) major parts:

Drilling Program in Dialog Format (in the following text)
Drilling Program by Task (in Appendix A)
Electric Logging Program (in Appendix A)
Casing Program and Specifications (in Appendix A)
Cementing Equipment Data (in Appendix A)
Cement Program (in Appendix A)

DRILLING PROGRAM IN DIALOG FORMAT

All depths referenced in this drilling program are based upon the drilling rig's rotary kelly bushing being eighteen feet above ground level. All depths have been approximated using historical drilling data from the other wells and regional information. Actual formation and completion depths will be based on in-situ logging conducted during the drilling and steel line measurements made during installation. All of the cementing volumes used to calculate material requirements are based on gauge hole. Actual cement volumes and final cement additive selection will be based on log information and drilling conditions. A completion report containing all of the required and pertinent information will be prepared and submitted after construction is completed. The actual depths and volumes used will be included in the report.

It is BSC's practice to keep the USEPA UIC technical personnel fully appraised of drilling activities by means of a faxed daily report and telephone conversations. This program will be incorporated into the reporting of all activities during drilling and completion based upon mutual agreement of subject and content between BSC and the UIC group. This drilling program sets forth the minimum construction standards and procedures that will be used during construction. Major or minor changes required by actual drilling conditions will be discussed with the proper regulatory personnel as they arise.

After the site is cleared and graded, a 30" conductor will be driven to 40 feet or refusal by pile driving or drilled and cemented using a conductor setting service.

CONDUCTOR: Surface to 40' or point of refusal
30", .375" or .500" wall, carbon steel

During the drilling of the Galesville monitoring well, severe washout beneath the drilling rig sub-structure occurred. To reduce the chance of reoccurrence, a driven conductor has been added.

After the conductor is in place, a suitable drilling rig will be moved to location and rigged up. A flow line connecting the steel recirculating tanks into the side of the conductor will be welded in place. The rig will utilize a closed loop mud system during drilling. All generated cuttings will be collected in steel pits for disposal on site. Fluids will be collected and properly disposed using BSC's appropriate liquid and sludge facilities.

Following rig up, a 26" hole will be drilled from the surface to 245 feet through the glacial deposits and approximately 45 feet into the top of the Silurian-Devonian formation. A 20" threaded and coupled conductor will be run in the hole and cemented using conventional cement circulation techniques. A cement volume of no less than 100% excess of the calculated hole volume will be pumped initially. If the cement top falls back after cementing, the annulus will be filled with additional cement by the tremie method. The casing will remain hung from the rig for a minimum of 24 hours to allow the cement to cure without disturbance.

SURFACE CONDUCTOR:

Surface to 240 feet
20", J-55, 94 lbs/ft, 8rd, ST&C

Drift Diameter:	18.936 inches
O.D. of Coupling:	21.000 inches
Collapse:	520 psi
Body Yield	1,480,000 pounds
Internal Yield	2,110 psi
Joint Strength:	784,000 pounds

SURFACE CONDUCTOR CEMENTING EQUIPMENT

Item #	Qty	Description
1.	1	20" guide shoe with float
2.	1 jt	20", 94 lbs/ft, J or K-55, 8rd, ST&C
	2	Steel spring centralizer, 1- 10' above shoe, 1-10'feet below collar
3.	1	Stab-in float sub
4.	5 jts	20", 94 lbs/ft, J or K-55, 8rd, ST&C
	2	Steel spring centralizer 1- between joints 3&4, 1- between joints 1&2

Note relative to all cementing:

All capacities, volumes, pipe weights, diameters, etc. were obtained from Halliburton Cementing Tables per standard API practice.

Surface Conductor Cement:
Casing: 20", J-55, 94 lbs/ft, ST&C
Cement: Class A with 2% Calicum Chloride

		Size		Volume Constant
Hole Diameter		26"		3.69 cu ft/ In ft
Capacity of open hole annulus		20" vs 26"		1.51 cu ft/ In ft
Capacity of cased hole annulus		20" vs 30"		2.48 cu ft/ In ft
Capacity of 20" Casing				1.99 cu ft/ In ft
	Top (ft)	Bottom (ft)	Total	
Cased hole depth	0	40	40 feet	
Cased open hole	40	240	200 feet	
Open hole	240	245	5 feet	

Annular Volume	20" vs 30"	99.39 cu ft	40 ft* 2.4847 cu ft/ln ft
Annular Volume	20" vs 26"	301.06 cu ft	200 ft *1.5053 cu ft/ln ft
Hole Volume	26"	18.44 cu ft	5 ft * 3.6870cu ft/ln ft
Volume Left in 20" casing (40 feet)		79.79 cu ft	40 ft * 1.9947 cu ft/ln ft
	Total	498.67 cu ft	
	100% excess	498.67 cu ft	
	Total volume	997.34 cu ft	

Yield Per Sack	1.36 cu ft/sk
No. of Sacks	733 sacks

A 20" casing head will be welded to the casing and blow out preventors (BOP's) mounted. A new flow line and drilling nipple suitable to mount air assist drilling equipment will be fabricated and mounted above the BOP's. The BOP's will be pressure tested to 1000 psi using a test plug in the casing head. Drilling will proceed after testing is completed.

A 17-1/2" diameter hole will be drilled from 245 feet to approximately 1200 feet using water and gel sweeps to keep the hole clean. If necessary, air assisted drilling techniques will be used to drill a portion of the well. Single shot deviation surveys will be run at least once every 300 feet to insure the angle of deviation is less than 3°. During drilling, a mud logger will be on site to collect three sets of dry cutting samples. Samples will be collected no less than once every 30 feet.

Drilling the surface casing hole to 1200 feet is a major change from previous well construction at BSC. The change is based on the lost circulation zone encountered while drilling in the Trenton formation during the construction of the Galesville monitoring well. After setting surface casing at 950 feet, a major lost circulation zone was encountered at approximately 1067 feet. To prevent this from re-occurring on this well, the design includes drilling through the Trenton formation and into the top of the Black River formation before setting surface casing. This will isolate any Trenton high porosity/low pressure zones during deeper drilling operations. Special two stage cementing procedures are included to deal with the Trenton should lost circulation occur and to insure the competency of the cement job.

After the well is drilled to 1200 feet a complete suit of open hole logs with be run.

SURFACE CONDUCTOR OPEN HOLE LOGGING

Dual Induction- Spontaneous Potential - Gamma Ray
Formation Density - Compensated Neutron - Gamma Ray
Open Hole Caliper - Gamma Ray

After the logs are complete a clean up trip will be made to clear the hole of any accumulated drilling debris. Casing crews will be rigged up to properly torque and install approximately 1200 feet of 13-3/8 inch, 54.50 pound/foot, J or K-55, casing. The casing will include a guide shoe with internal float, a float collar, an external casing packer, a sliding sleeve port collar and sufficient spring steel centralizers to center the casing in the hole. After the casing is installed, inter-string cementing tools will be made up to the drill pipe and run inside of the casing. The lower stinger will be engaged and the casing circulated to clear debris from the hole. The first stage of the cement job is planned to utilize a minimum cement volume equal to no less than of 120% of the measured hole volume from total depth to approximately 900 feet. Class A cement with 2% calcium chloride is planned for this stage. After the cement is circulated into place, the inter-string will be moved to inflate the external casing packer. This procedure will isolate additional cement column pressure from being exerted on the Trenton formation. After inflating the external casing packer, the sliding sleeve port collar will be opened and any excess first stage cement will be circulated from the annulus. The second stage cementing will begin immediately after the excess cement is circulated from the hole. A combination of light weight lead cement and dense tail cement will be used to cement the second stage. Following the cementing procedure, the casing will be hung from the drilling rig for a minimum of 24 hours.

SURFACE CASING:

Surface to1200 feet

13-3/8", J or K-55, 54.50 lbs/ft, 8rd, ST&C

Drift Diameter:	12.459 inches
O.D. of Coupling:	14.375 inches
Collapse:	1,130 psi
Body Yield	853,000 pounds
Internal Yield	2,730 psi
Joint Strength:	547,000 pounds

SURFACE CASING CEMENTING EQUIPMENT:

Item #	Qty	Description
1.	1	13-3/8" guide shoe with float
2.	1 jt	13-3/8", 54.50 lbs/ft, J or K-55, 8rd, ST&C
	2	Steel spring centralizer, 1- 10' above shoe, 1-10'feet below collar
3.	1	Stab-in float sub
4.	4 jts	13-3/8", 54.50 lbs/ft, J or K-55, 8rd, ST&C
	2	Steel spring centralizer 1 - between joints 2&3, 1- between joints 4&5
	2	Canvas cement baskets on the 10' and 20' from the top of joint 6
5.	2 jts	13-3/8", 54.50 lbs/ft, J or K-55, 8rd, ST&C
6.	1	13-3/8" External Casing Packer
7.	1	13-3/8" Sliding Sleeve Port Collar
8.	23 jts	13-3/8", 54.50 lbs/ft, J or K-55, 8rd, ST&C
	7	Steel spring centralizers, 1 every third joint starting with the top of joint 9

Surface Casing Cement:

First Stage

Casing: 13-3/8", J or K-55, 54.50 lbs/ft, ST&C
Cement: Class A with 2% Calcium Chloride

Hole Diameter	17 1/2"	1.67	cu ft/ln ft
Capacity of open hole annulus	13-3/8" vs 17-1/2"	0.69	cu ft/ln ft
Capacity of cased hole annulus	13-3/8" vs 20"	1.01	cu ft/ln ft
Capacity of 13-3/8" Casing		0.86	cu ft/ln ft

	Top (ft)	Bottom (ft)	Total (ft)
Cased open hole	900	1200	300 feet
Open hole	1200	1210	10 feet

Annular Volume 13-3/8" in 17-1/2"	208.38	cu ft
Hole Volume	16.70	cu ft
Volume Left in 13-3/8" casing (40 ft)	34.71	cu ft
Total	259.79	cu ft
20% excess	51.95	cu ft
Total volume	311.75	cu ft

Yield Per Sack 1.36 cu ft/sk
No. of Sacks 229 sacks

Surface Casing Cement

Second Stage Lead cement

Cement: Class A Lite

	Size	Volume Constant	
Hole Diameter	17 1/2"	1.67	cu ft/ln ft
Capacity of open hole annulus	13-3/8" vs 17-1/2"	0.69	cu ft/ln ft
Capacity of cased hole annulus	13-3/8" vs 20"	1.01	cu ft/ln ft
Capacity of open hole		1.67	cu ft/ln ft
Capacity of 13-3/8" Casing		0.86	cu ft/ln ft

	Top (ft)	Bottom (ft)	Total (ft)
Cased hole depth	0	240	240 feet
Cased open hole	240	700	460 feet

Annular Volume 13-3/8" in 20"	244.56	cu ft
Annular Volume 13-3/8" in 17-12"	319.51	cu ft
Total	564.07	cu ft
20% excess	112.81	cu ft
Total volume	676.89	cu ft

Yield Per Sack 2.06 cu ft/sk
No. of Sacks 329 sacks

(cont.)

Surface Casing Cement

Second Stage Tail cement

Cement: Class A with 2% Calicum Chloride

Hole Diameter	17 1/2"		1.67 cu ft/ln ft
Capacity of open hole annulus	13-3/8" vs 17-1/2"		0.69 cu ft/ln ft
Capacity of cased hole annulus	13-3/8" vs 20"		1.02 cu ft/ln ft
Capacity of 13-3/8" Casing			0.87 cu ft/ln ft

	Top (ft)	Bottom (ft)	Total (ft)
Cased open hole	700	900	200 feet

Annular Volume 13-3/8" in 17-12"		138.92 cu ft
	Total	138.92 cu ft
	20% excess	27.78 cu ft
	Total volume	166.70 cu ft

Yield Per Sack	1.36 cu ft/sk
No. of Sacks	123 sacks

After waiting 24 hours, the flow line and BOP's will be removed. A casing spool, hanger and seals will be installed. The BOP's and flow line will be re-installed. After 72 hours of cure time, a cement bond log with variable density will be run.

Cased Hole Logging Program

Single Pass Temperature
Cement Bond with Variable Density

If the bond log records sufficient cement bond, work will continue. If insufficient cement bonding is shown, a remedial cementing plan will be initiated before drilling out. The casing will be pressure tested to 1000 psi for one hour. If the test pressure changes less than 3%, the casing pressure test will be considered acceptable.

A 12-1/4 inch diameter drill bit will be used to drill out the float shoe, cement remaining in the casing and the guide shoe. A 12-1/4 inch hole will be drilled from 1200 feet to the top of the Precambrian Formation using water, gel sweeps, and possibly air assisted drilling techniques to keep the hole clean of cuttings. The Precambrian is expected to be encountered between 4300 feet and 4400 feet. Once the Precambrian is encountered the 12-1/4" hole will be extended into the formation if it can be easily drilled. No more than 20 feet of Precambrian is expected to be drilled.

After the drilling is completed, the hole will be circulated clean and then logged.

PROTECTION CASING OPEN HOLE LOGGING

Dual Induction- Spontaneous Potential - Gamma Ray
Formation Density - Compensated Neutron - Gamma Ray
Open Hole Caliper - Gamma Ray
Gyroscopic Deviation Survey

Following the open hole logging, a series of fracture gradient tests will be performed. Three intervals (one upper, one middle, one lower) within the lower Mount Simon formation will be selected based on borehole geometry, porosity and density. Inflatable straddle packers will be used to isolate each of the three selected zones from the remainder of the hole section. Either increasing flow rate step testing or flow rate reduction testing will be used to determine the fracture initiation pressure, fracture propagation pressure, and the fracture closure pressure. Water will be used during the fracturing tests.

After completing the fracture gradient tests, the straddle packers will be used to recover a sample of fluid from the upper Mount Simon formation (2580 feet-2620 feet). ← after frac test?
A small inner string will be made up and lowered into the workstring so that nitrogen can be used to produce the fluid. After the fluid is recovered, the well will be allowed to recover and the fluid level measured to determine the bottom hole pressure of the upper Mount Simon.

No cores are planned to be taken in this well due to the previous coring performed during the drilling of the Galesville Monitor well and the existence from the cores taken during the drilling of the Midwest Steel well. Midwest data was previously used to determine the properties of the lower well formations in the petition modeling.

After the fracturing tests and fluid recovery are completed, the straddle packers will be removed from the well bore and a clean-up trip made. Casing crews will be used to properly tighten the 9-5/8 inch protection casing while it is being run into the wellbore. The protection casing will be run to a depth of approximately 2765 feet. The actual depth will be determined from the logs. It is planned to set the external casing packer immediately below the top of the lower Mount Simon formation. A carbon steel guide shoe will be threaded to a Hastelloy external casing packer and run in the hole beneath the protection casing. The lowermost section of the protection casing will consist of 8-5/8", sch 40 or sch 80 Hastelloy C-276. A polished bore casing receptacle made from 8-5/8", sch 80 Hastelloy C-276 pipe will be run next. A cross over will connect the Hastelloy to the 9-5/8", 40#/ft, N-80 carbon steel casing. Another external casing packer and sliding sleeve port collar will be installed at approximately 2050 feet. Once the casing is in place, an inner string with port collar tools will be lowered into the casing. The well will be circulated clean. The lower section of the casing from 2765 feet to 2050 feet will be cemented with Epseal epoxy resin cement. The upper section of casing from 2050 feet to surface will be cemented with a combination of Class A cement and Class A Lite cement.

PROTECTION CASING: Surface to 2700 feet

9-5/8", N-80, 40 lbs/ft, 8rd, LT&C

Drift Diameter:	8.679 inches
O.D. of Coupling:	10.625 inches
Collapse:	3,090 psi
Body Yield	916,000 pounds
Internal Yield	5,750 psi
Joint Strength:	737,000 pounds

ACID RESISTANT CASING AND POLISHED BORE RECEPTACLE:

8" Hastelloy C-276, Sch-80 with "O"ring sealed square acme threads. Total length ± 40 feet. Set 2700 to 2740 feet. Total BHA with sliding sleeve, external casing packer and guide shoe: ± 2755 feet. I.D. of PBR: 7.75 inches

PROTECTION CASING CEMENTING EQUIPMENT

Item #	Qty	Description
1.	1	8-5/8" External Casing Packer with guide shoe.
2.	1	8-5/8" Hastelloy Sliding Sleeve Port Collar
3.	1	8-5/8" Hastelloy PBR Extension
4.	1	8-5/8" Hastelloy Polished Bore Receptacle
5.	1	8-5/8" by 9-5/8" cross over sub
6.	17 jts	9-5/8", 40 lbs/ft, N-80, 8rd, LT&C
	3	8-5/8" Steel spring centralizer, 1- 10' above port collar, 1 on extension, 1 on PBR
	8	9-5/8" Steel Spring Centralizer, 1 on every other joint
7.	1	9-5/8" External casing Packer
8.	1	9-5/8", Sliding Sleeve Port Collar
9.	51jts	9-5/8", 40 lbs/ft, N-80, 8rd, LT&C
	17	9-5/8" Steel Spring Centralizer, 1 on every third joint

Protection Casing Cement

First Stage

Cement: Epseal Epoxy Resin Slurry

Hole Diameter		12-1/4"		1.67 cu ft/ln ft	
Capacity of open hole annulus		9-5/8" vs 12-1/4"		0.69 cu ft/ln ft	2.34 gals/ln ft
Capacity of open hole annulus		8-5/8" vs 12-1/4"			3.09 gals/ln ft

	Top (ft)	Bottom (ft)	Total (ft)
Cased hole depth	0	0	0 feet
Cased open hole 9-5/8"	2050	2625	575 feet
Cased open hole 8-5/8"	2625	2665	40 feet

Annular Volume 9-5/8" in 12-1/4"	1347.11 gals
Annular Volume 8-5/8" in 12-1/4"	123.50 gals
Total	1470.61 gals
10% excess	147.06 gals
Total volume	1617.67 gals

Protection Casing Cement

Second Stage Lead

Cement: Class A Lite

Hole Diameter		12-1/4"		0.82 cu ft/ln ft
Capacity of open hole annulus		9-5/8" vs 12-1/4"		0.31 cu ft/ln ft
Capacity of cased hole annulus		9-5/8" vs 13-3/8"		0.36 cu ft/ln ft
Capacity of 9-5/8" Casing				0.87 cu ft/ln ft
	Top (ft)	Bottom (ft)	Total (ft)	
Cased hole depth	0	1200	1200 feet	
Cased open hole 9-5/8"	1200	1850	650 feet	

Annular Volume 9-5/8" in 12-1/4"	203.58 cu ft
Annular Volume 9-5/8" in 13-3/8"	435.24 cu ft
Total	638.82 cu ft
20% excess	127.76 cu ft
Total volume	766.58 cu ft

Yield Per Sack	2.06 cu ft/sk
No. of Sacks	372 sacks

Protection Casing Cement

Second Stage Tail

Cement: Class A with 2% Calciuum Chloride

Hole Diameter		12-1/4"		
Capacity of open hole annulus		9-5/8" vs 12-1/4"		0.31 cu ft/ln ft
Capacity of open hole		12-1/4"		0.82 cu ft/ln ft
Cased open hole 9-5/8"	1850	2050	200 Total feet	

Annular Volume 9-5/8" in 12-1/4"	62.64 cu ft
20% excess	12.53 cu ft
Total volume	75.17 cu ft

Yield Per Sack	2.06 cu ft/sk
No. of Sacks	36 sacks

The casing will be hung from the drilling rig for a minimum of twenty-four hours while the cement is initially allowed to cure. After twenty-four hours has expired, the casing will be cut, the BOP's removed, a 9-5/8 inch hanger, seal and a tubing spool installed. The cement will be allowed to cure for 72 total hours after pumping. A logging truck will be rigged up to run the following logs:

CASED HOLE LOGGING PROGRAM (72 hours after cementing)

Cement Bond with Variable Density
Temperature Log
Electro-Magnetic Casing Inspection

After logging, a test seal will be made unto the bottom of the work string and lowered into the casing polished bore receptacle. The casing will be pressure tested to 1000 psi for one hour. If the test pressure does not change more than 3% during the hour, the test will considered acceptable. After pressure testing, the well bore will be stimulated by nitrogen jetting, acidizing and nitrogen jetting. During the first jetting phase, samples of formation fluid will be collected.

what if not?

After stimulation, an injectivity/fall-off test will be performed followed by a radioactive tracer log. The logging tools will be rigged down and casing crews rigged up to install the 5-1/2" fiberglass injection tubing.

TUBING:

Surface to 2775 feet
5-1/2", Red Box 2500, 7.3 lbs/ft, 8rd, LT&C

Drift Diameter:	5.53 inches
O.D. of Coupling:	6.78 inches
Collapse:	3,300 psi
Internal Yield	2,500 psi
Joint Strength:	54,500 pounds

Once the tubing is run, the tubing will be spaced out and the annulus filled with inhibited NaCl brine. The seal assembly will be landed in the polished bore receptacle. The annulus will be topped off with food grade mineral oil. The BOP's will be removed and the tubing hung off in the tubing spool. The annulus will be pressure tested to 1000 psi for one hour. If the test pressure changes less than 3% during the hour, the test will be considered acceptable.

The drilling rig will be rigged down and removed from location. The location will be cleared and construction will begin on the surface facilities. A report fully detailing the work will be prepared and submitted to the USEPA along with a modification request to the current petition for exemption from the Land ban regulations

BETHLEHEM STEEL CORPORATION
BURNS HARBOR DIVISION
WAL/SPL-1
DRILLING PROGRAM

STEP	TASK
1	Prepare the location by removing as much miscellaneous equipment from the area as possible.
2.	Survey the location and stake the well site.
3.	Drive a 30 inch diameter, 0.375 inch or .500 inch wall carbon steel conductor to 40 feet or refusal.
4.	Move in and rig up the drilling rig with all the necessary ancillary equipment. The rig should include a substructure with rotary table, two sets of pipe racks, catwalk and V-door, two steel tanks, two mud pumps, dog house, adequate generators for the mud system and the rig, drilling instrumentation and slick line.
5.	Set up a closed mud system which includes shakers, de-sander, de-silter and centrifuge. All drill cuttings will be placed in a roll off box for disposal.
6.	Drill the rat hole and mouse hole.
7.	Drill a 26 inch hole to approximately 240 feet using water and native mud. A single shot deviation survey will be made every third joint drilled (approximately 100 feet).
8.	Circulate and condition the hole for casing.
9.	Install approximately 240 feet of 20 inch, 94 pounds/foot, J or K-55, 8 rd, ST&C casing with a sting in guide shoe and float.
10.	Pick up an inner-string and stab into the guide shoe.
11.	Circulate the hole clean
12.	Cement the casing with Class A cement with 2% calcium chloride. The calculated volume plus 100% excess will be emplaced. After cementing the casing, clean out any excess cement from the cellar. If the cement fails to come to surface, top off the annulus by the tremmie method using Class A cement.
13.	Allow the cement to cure for 24 hours while hanging from the rig.

14. Cut off the excess casing. Weld on a casing head. Mount a blow out preventer (BOP) and flow line. Move in and rig a mud logger to catch and describe drilling samples.

15. Pressure test the BOP at 1000 psi.

16. A 17-1/2 inch bit will be used to drill the surface hole. The well will be drilled using fresh water. High viscosity gel-lime sweeps will be made every 100 feet, if needed. Pick up a 17-1/2 inch bit with sufficient drill collar weight.

17. Drill the surface hole to 1200 feet. Catch wet and dry drilled cuttings samples every 30 feet. Take a single shot survey approximately every 300 feet. The maximum deviation in the well will be 3 degrees or less.

18. Circulate and condition the hole for logs. Rig up the electric loggers. Run the following electric logs from 1200 feet to surface:
    A) Dual Induction - Spontaneous Potential - Gamma Ray
    B) Formation Density - Compensated Neutron - Gamma Ray
    C) Open Hole Caliper - Gamma Ray

19. Circulate and condition the hole for casing. Drift the casing on the racks when it arrives, clean and visually inspect all the threads on the pins and couplings. Rig up to run the 13-3/8 inch, 54.5 lb/ft, J or K -55 casing to approximately 1200 feet.

20. Pick up and run the inner-string and stab in guide.

21. Rig up to cement. Circulate one annulus volume of clean water prior to cementing. Cement from 1200 feet to surface following the attached cementing program.

22. Allow the cement to cure for a minimum of 24 hours while hanging from the slips.

23. Cut off the casing to the proper height and mount a casing spool, hanger and seals.

24. Nipple up the BOP. Function test the BOP. Pressure test the BOP and lines to 2,000 psig using a test plug.

25. Wait on cement for 72 hours prior to cased hole logging operations.

26. Rig up the electric loggers and run the following electric logs from casing plug back TD to surface:
    A. Cement Bond log with Variable Density
    B. Temperature Log

27. Pressure test the casing to 1000 psi for one hour. The test will be considered successful if there is less than a 3% gain or loss in pressure after one hour.

28. Pick up a 12-1/4 inch bit and bottomhole assembly and run in the well with the drill pipe. Drill out the surface casing. Do not exceed 10,000 lbs bit weight or 50 rpm rotary while drilling out the float and shoe.

29. Drill a 12-1/4 inch hole from approximately 1200 feet to approximately 4400 feet. Catch wet and dry samples every 30 feet. Take a single shot survey every third joint drilled (approximately every 300 feet). The maximum deviation will be 3 degrees or less.

30. Circulate and condition the hole for logs. Rig up the electric loggers. Run the following electric logs from 4400 feet to 1200 feet:
    A. Dual Induction - Spontaneous Potential - Gamma Ray
    B. Formation Density - Compensated Neutron - Gamma Ray
    C. Open Hole Caliper - Gamma Ray
    D. Gyroscopic survey from surface to total depth

31. Perform open hole fracture gradient testing with straddle packers in the Mt. Simon formation as described in the fracture gradient test plan.

32. Recover a fluid sample from the upper Mt. Simon formation using the straddle packers, an inner string and nitrogen jetting

33. Release the packer and pull out of the hole. Lay down the inflatable open hole tools.

34. Run in the hole with the drill string to circulate and condition the hole for casing. Pull out of the hole laying down.

35. Drift the casing on the racks when it arrives, clean and visually inspect all the threads on the pins and couplings. Pull out of the hole with the drill string. Rig up to run the 9-5/8 inch 40 lb/ft N-80 casing to 2765 feet per the casing and cementing equipment programs.

36. Run in the hole with the TAM cementing tools on drill pipe. Cement per the cementing program.

37. Cut off the casing to the proper height and install the hanger, casing spool and seals after 24 hours of waiting for the cement to cure..

38. Nipple up the BOP. Function test the BOP. Pressure test the BOP and lines to 2,000 psig.

39. Wait on cement for 72 hours prior to cased hole logging operations.

40. Rig up the electric loggers and run the following electric logs from casing plug back TD to surface:
    A. Temperature Log
    B. Cement Bond Log with Variable Density
    C. Electro Magnetic Casing Inspection Log
    D. Radioactive Tracer

41. Pick up an inflatable packer *or test seal*, go in the hole and set the packer 10 feet above the casing shoe. Pressure test the casing to 1000 psi for one hour. If the pressure changes less than 3% in the one hour period the test will be considered successful.

42. Stimulate the well as described in the stimulation plan.

43. Pull out of the hole and lay down the work string.

44. Rig up and run the seal assembly and 5-1/2" fiberglass injection tubing. Tag up and space out

45. Displace the annulus with fresh water and top off with food grade mineral oil for freeze protection (approximately 30 feet of mineral oil).

46. Hang off the tubing in the wellhead.

47. Pressure test the annulus to 1000 psi for one hour. If the annulus pressure changes less than 3% after one hour the test will be considered acceptable.

48. Clean the mud system and dispose of fluids and drilled solids properly. Rig down the drilling rig and move off.

BETHLEHEM STEEL CORPORATION
BURNS HARBOR DIVISION
WAL/SPL-1
LOGGING PROGRAM

Surface Hole

Open Hole
- Dual Induction- Spontaneous Potential-Gamma Ray
- Formation density-Compensated Neutron-Gamma ray
- Open Hole Caliper- Gamma Ray

Cased Hole (72 hours after cementing)
- Cement Bond with Variable Density
- Temperature Log

Protection Hole

Open Hole
- Dual Induction- Spontaneous Potential-Gamma Ray
- Formation density-Compensated Neutron-Gamma ray
- Open Hole Caliper- Gamma Ray
- Gyroscopic Survey

Cased Hole (72 hours after cementing)
- Cement Bond with Variable Density
- Temperature Log
- Electro-Magnetic Casing Inspection
- Radioactive Tracer

BETHLEHEM STEEL CORPORATION
BURNS HARBOR DIVISION
WAL/SPL-1
CASING PROGRAM AND SPECIFICATIONS

CONDUCTOR:

Surface to 40' or point of refusal
30", .375" or .500" wall, carbon steel

SURFACE CONDUCTOR:

Surface to 240 feet
20", J-55, 94 lbs/ft, 8rd, ST&C

Drift Diameter:	18.936 inches
O.D. of Coupling:	21.000 inches
Collapse:	520 psi
Body Yield	1,480,000 pounds
Internal Yield	2,110 psi
Joint Strength:	784,000 pounds

SURFACE CASING:

Surface to 970 feet
13-3/8", J or K-55, 54.50 lbs/ft, 8rd, ST&C

Drift Diameter:	12.459 inches
O.D. of Coupling:	14.375 inches
Collapse:	1,130 psi
Body Yield	853,000 pounds
Internal Yield	2,730 psi
Joint Strength:	547,000 pounds

PROTECTION CASING:

Surface to 2700 feet
9-5/8", N-80, 40 lbs/ft, 8rd, LT&C

Drift Diameter:	8.679 inches
O.D. of Coupling:	10.625 inches
Collapse:	3,090 psi
Body Yield	916,000 pounds
Internal Yield	5,750 psi
Joint Strength:	737,000 pounds

ACID RESISTANT CASING AND POLISHED BORE RECEPTACLE:

8" Hastelloy C-276, Sch-80 with "O"ring sealed square acme threads. Total length ± 40 feet. Set 2700 to 2740 feet. Total BHA with sliding sleeve, external casing packer and guide shoe: ± 2755 feet. I.D. of PBR: 7.75 inches

TUBING:

	Surface to 2775 feet	
	5-1/2", Red Box 2500, 7.3 lbs/ft, 8rd, LT&C	
	Drift Diameter:	5.53 inches
	O.D. of Coupling:	6.78 inches
	Collapse:	3,300 psi
	Internal Yield	2,500 psi
	Joint Strength:	54,500 pounds

BETHLEHEM STEEL CORPORATION
BURNS HARBOR DIVISION
WAL/SPL-1
CEMENTING EQUIPMENT

Surface Conductor

Item #	Qty	Description
1.	1	20" guide shoe with float
2.	1 jt	20", 94 lbs/ft, J or K-55, 8rd, ST&C
	2	Steel spring centralizer, 1- 10' above shoe, 1-10'feet below collar
3.	1	Stab-in float sub
4.	5 jts	20", 94 lbs/ft, J or K-55, 8rd, ST&C
	2	Steel spring centralizer 1- between joints 3&4, 1- between joints 1&2

Surface Casing

Item #	Qty	Description
1.	1	13-3/8" guide shoe with float
2.	1 jt	13-3/8", 54.50 lbs/ft, J or K-55, 8rd, ST&C
	2	Steel spring centralizer, 1- 10' above shoe, 1-10'feet below collar
3.	1	Stab-in float sub
4.	4 jts	13-3/8", 54.50 lbs/ft, J or K-55, 8rd, ST&C
	2	Steel spring centralizer 1 - between joints 2&3, 1- between joints 4&5
	2	Canvas cement baskets on the 10' and 20' from the top of joint 5
5.	2 jts	13-3/8", 54.50 lbs/ft, J or K-55, 8rd, ST&C
6.	1	13-3/8" External Casing Packer
7.	1	13-3/8" Sliding Sleeve Port Collar
8.	23 jts	13-3/8", 54.50 lbs/ft, J or K-55, 8rd, ST&C
	7	Steel spring centralizers, 1 every third joint starting with the top of joint 8

Protection Casing

Item #	Qty	Description
1.	1	8-5/8" External Casing Packer with guide shoe.
2.	1	8-5/8" Hastelloy Sliding Sleeve Port Collar
3.	1	8-5/8" Hastelloy PBR Extension
4.	1	8-5/8" Hastelloy Polished Bore Receptacle
5.	1	8-5/8" by 9-5/8" cross over sub
6.	17 jts	9-5/8", 40 lbs/ft, N-80, 8rd, LT&C
	3	8-5/8" Steel spring centralizer, 1- 10' above port collar, 1 on extension, 1 on PBR
	8	9-5/8" Steel Spring Centralizer, 1 on every other joint
7.	1	9-5/8" External casing Packer
8.	1	9-5/8", Sliding Sleeve Port Collar
9.	51jts	9-5/8", 40 lbs/ft, N-80, 8rd, LT&C
	17	9-5/8" Steel Spring Centralizer, 1 on every third joint

Bethlehem Steel Corporation
Burns Harbor Division
WAL/SPL #1 Cement Calculations:

All capacities, volumes, pipe weights, diameters, etc. were obtained from Halliburton Cementing Tables per standard API practice.

Surface Conductor Cement:
Casing: 20", J-55, 94 lbs/ft, ST&C
Cement: Class A with 2% Calicum Chloride

	Size	Volume Constant
Hole Diameter	26"	3.69 cu ft/ ln ft
Capacity of open hole annulus	20" vs 26"	1.51 cu ft/ ln ft
Capacity of cased hole annulus	20" vs 30"	2.48 cu ft/ ln ft
Capacity of 20" Casing		1.99 cu ft/ ln ft

	Top (ft)	Bottom (ft)	Total
Cased hole depth	0	40	40 feet
Cased open hole	40	240	200 feet
Open hole	240	245	5 feet

Annular Volume	20" vs 30"	99.39 cu ft	40 ft* 2.4847 cu ft/ln ft
Annular Volume	20" vs 26"	301.06 cu ft	200 ft *1.5053 cu ft/ln ft
Hole Volume	26"	18.44 cu ft	5 ft * 3.687 cu ft/ln ft
Volume Left in 20" casing (40 feet)		79.79 cu ft	40 ft * 1.9947 cu ft/ln ft
	Total	498.67 cu ft	
	100% excess	498.67 cu ft	
	Total volume	997.34 cu ft	

Yield Per Sack	1.36 cu ft/sk
No. of Sacks	733 sacks

Surface Casing Cement:

First Stage

Casing: 13-3/8", J or K-55, 54.50 lbs/ft, ST&C
Cement: Class A with 2% Calcium Chloride

Hole Diameter		17 1/2"		1.67 cu ft/ ln ft
Capacity of open hole annulus		13-3/8" vs 17-1/2"		0.69 cu ft/ ln ft
Capacity of cased hole annulus		13-3/8" vs 20"		1.02 cu ft/ ln ft
Capacity of 13-3/8" Casing				0.87 cu ft/ ln ft
	Top (ft)	Bottom (ft)	Total (ft)	
Cased open hole	900	1200	300 feet	
Open hole	1200	1210	10 feet	

Annular Volume 13-3/8" in 17-1/2"	208.38 cu ft
Hole Volume	16.70 cu ft
Volume Left in 13-3/8" casing (40 ft)	34.72 cu ft
Total	259.80 cu ft
20% excess	51.96 cu ft
Total volume	311.76 cu ft

Yield Per Sack	1.36 cu ft/sk
No. of Sacks	229 sacks

Surface Casing Cement

Second Stage Lead cement

Cement: Class A Lite

		Size		Volume Constant
Hole Diameter		17 1/2"		1.67 cu ft/ ln ft
Capacity of open hole annulus		13-3/8" vs 17-1/2"		0.69 cu ft/ ln ft
Capacity of cased hole annulus		13-3/8" vs 20"		1.02 cu ft/ ln ft
Capacity of open hole				1.67 cu ft/ ln ft
Capacity of 13-3/8" Casing				0.87 cu ft/ ln ft
	Top (ft)	Bottom (ft)	Total (ft)	
Cased hole depth	0	240	240 feet	
Cased open hole	240	700	460 feet	

Annular Volume 13-3/8" in 20"	244.56 cu ft
Annular Volume 13-3/8" in 17-12"	319.52 cu ft
Total	564.08 cu ft
20% excess	112.82 cu ft
Total volume	676.89 cu ft

Yield Per Sack	2.06 cu ft/sk
No. of Sacks	329 sacks

Surface Casing Cement

Second Stage Tail cement

Cement: Class A with 2% Calicum Chloride

Hole Diameter	17 1/2"			1.67 cu ft/ ln ft
Capacity of open hole annulus	13-3/8" vs 17-1/2"			0.69 cu ft/ ln ft
Capacity of cased hole annulus	13-3/8" vs 20"			1.02 cu ft/ ln ft
Capacity of 13-3/8" Casing				0.87 cu ft/ ln ft
	Top (ft)	Bottom (ft)	Total (ft)	
Cased open hole	700	900	200 feet	

Annular Volume 13-3/8" in 17-12"	138.92	cu ft
Total	138.92	cu ft
20% excess	27.78	cu ft
Total volume	166.70	cu ft

Yield Per Sack	1.36	cu ft/sk
No. of Sacks	123	sacks

Protection Casing Cement

First Stage

Cement: Epseal Epoxy Resin Slurry

Hole Diameter		12-1/4"		1.67 cu ft/ ln ft	
Capacity of open hole annulus		9-5/8" vs 12-1/4"		0.69 cu ft/ ln ft	2.34 gals/ln ft
Capacity of open hole annulus		8-5/8" vs 12-1/4"			3.09 gals/ln ft
	Top (ft)	Bottom (ft)	Total (ft)		
Cased hole depth	0	0	0 feet		
Cased open hole 9-5/8"	2050	2625	575 feet		
Cased open hole 8-5/8"	2625	2665	40 feet		

Annular Volume 9-5/8" in 12-1/4"	1347.11 gals
Annular Volume 8-5/8" in 12-1/4"	123.50 gals
Total	1470.61 gals
10% excess	147.06 gals
Total volume	1617.67 gals

Protection Casing Cement

Second Stage Lead

Cement: Class A Lite

Hole Diameter		12-1/4"		0.82 cu ft/ ln ft
Capacity of open hole annulus		9-5/8" vs 12-1/4"		0.31 cu ft/ ln ft
Capacity of cased hole annulus		9-5/8" vs 13-3/8"		0.36 cu ft/ ln ft
Capacity of 9-5/8" Casing				0.87 cu ft/ ln ft
	Top (ft)	Bottom (ft)	Total (ft)	
Cased hole depth	0	1200	1200 feet	
Cased open hole 9-5/8"	1200	1850	650 feet	

Annular Volume 9-5/8" in 12-1/4"	203.58 cu ft
Annular Volume 9-5/8" in 13-3/8"	435.24 cu ft
Total	638.82 cu ft
20% excess	127.76 cu ft
Total volume	766.58 cu ft

Yield Per Sack	2.06 cu ft/sk
No. of Sacks	372 sacks

Protection Casing Cement

Second Stage Tail

Cement: Class A with 2% Calciuum Chloride

Hole Diameter		12-1/4"		
Capacity of open hole annulus		9-5/8" vs 12-1/4"		0.31 cu ft/ in ft
Capacity of open hole		12-1/4"		0.82 cu ft/ in ft
Cased open hole 9-5/8"	1850	2050	200 Total feet	

Annular Volume 9-5/8" in 12-1/4"	62.64 cu ft
20% excess	12.53 cu ft
Total volume	75.17 cu ft

Yield Per Sack	2.06 cu ft/sk
No. of Sacks	36 sacks